VANCOUVER ISLAND ENERGY CORPORATION

APPLICATION TO THE BRITISH COLUMBIA UTILITIES COMMISSION
FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR

THE VANCOUVER ISLAND GENERATION PROJECT

MARCH 2003

105-03664/

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Executive Summary

Applicant Information

Vancouver Island Energy Corporation (VIEC) is a wholly-owned subsidiary of British Columbia Hydro and Power Authority (BC Hydro). VIEC applies to the British Columbia Utilities Commission (BCUC or Commission) pursuant to sections 45 and 46 of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473, to obtain a certificate of public convenience and necessity (CPCN) for the Vancouver Island Generation Project (VIGP).

Need for the VIGP

The need for new electricity supply to Vancouver Island is driven by the expected retirement of a significant part of the bulk transmission system from the Mainland to the Island.[1] That retirement will reduce BC Hydro's ability to meet the Island's peak demand by 240 megawatts (MW) in 2007. BC Hydro has concluded that it would be imprudent to continue to rely on this aging transmission system even with continued expenditures to maintain and repair it.

The VIGP is BC Hydro's preferred option for securing reliable electricity supply for Vancouver Island and the Gulf Islands. It removes the reliability risk with the greatest timing certainty, it is cost effective relative to the alternatives, and it maximizes BC Hydro's flexibility in planning for future electricity needs.

Project Description and Background

The project design incorporates a combined-cycle gas turbine (CCGT) power plant, a connection and upgrade to the existing transmission grid, a short feeder pipeline to supply natural gas to the plant, and related works. The plant will use proven high-efficiency technology to ensure that it is one of the cleanest and most reliable natural gas-fired generation facilities in North America. The project, with an expected in-service date of July 2006, 25-year life and total cost of $340 million,[2] will provide dependable capacity of 265 megawatts (MW) and have a firm annual energy capability of 2,100 gigawatt-hours (GWh).

The genesis of VIEC and the VIGP dates to the mid-1990s, when BC Hydro determined that security of the Island's electricity supply was becoming critical. Most of the electricity consumed on the Island is generated on the Mainland and delivered across the Georgia Strait by three underwater transmission systems. Given the age and deterioration of two of those systems, portions of which date to the 1950s, there are significant challenges to ensuring that electricity supply to Vancouver Island will remain secure and in compliance with BC Hydro and industry reliability standards, as adopted by BC Hydro. Since the mid-1990s, BC Hydro has consistently identified this as a regional supply problem for which new infrastructure is needed, whether in the form of on-Island generation, new transmission from the Mainland, or both.

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[1] All further references to Vancouver Island or "the Island" in this application include the Gulf Islands.

[2] Expressed in 2002 dollars and including contingencies, interest during construction (IDC), and corporate overhead. See Table 10 at page 77.

In 1994, pursuant to government policy of the day, a decision was made to address this regional supply problem by seeking proposals for new supply-side and demand-side resources to meet electricity demand on the Island and the province as a whole. After a government-sponsored review of these proposals, BC Hydro entered into an agreement to purchase the electricity output of the proposed Island Cogeneration Plant (ICP) near Campbell River.[3] That plant was built and became available for commercial operation in 2002. It is expected to provide BC Hydro with up to 240 megawatts (MW) of dependable generating capacity by 2005.

In response to a May 2000 government directive, BC Hydro also pursued another proposal, the Port Alberni Cogeneration Project (later called the Port Alberni Generation Project—PAGP), but negotiations with the project partners were unsuccessful. BC Hydro then worked with another partner to develop the PAGP. The parties made commitments to buy turbine equipment and applied to the Environmental Assessment Office (EAO) for a project approval certificate. A Minister's order exempted the project from the CPCN requirement. However, Port Alberni's municipal council refused zoning for the plant, after which the project approval application was withdrawn from the EAO.

VIEC was subsequently incorporated to carry out the project, renamed the VIGP. VIEC continued reviewing potential sites and ultimately developed the VIGP on its own. BC Hydro then acquired an industrial site from Pope & Talbot Ltd. at Duke Point in Nanaimo (the Harmac site), following a rigorous site selection process. The Harmac site is well suited for the project and satisfies the City of Nanaimo's zoning requirements. The VIGP's environmental impacts are the subject of a review of a new application for a project approval certificate, now called an environmental assessment certificate pursuant to recent legislative changes (the EAO Application).

Pursuant to the provincial government's November 2002 energy policy, this CPCN application is now being submitted to assist the Commission in reviewing the VIGP to ensure that it is the most cost-effective means of reliably meeting the Island's electricity needs.

Electricity Planning

BC Hydro serves more than 1.6 million customers throughout British Columbia. Its integrated system includes 29 hydroelectric stations, two thermal stations, and a 75,000 kilometre transmission and distribution network extending through most of the province. BC Hydro also buys electricity from independent power producers (IPPs) such as the ICP, and engages in wholesale electricity trades that provide it with system resource and reliability benefits. BC Hydro's mandate also includes non-power considerations relating to such things as flood control, air quality, domestic water supply, water transport, aesthetic requirements, recreation and maintenance of aquatic and terrestrial habitats. Thus decisions on the acquisition and timing of new resources are made with a view to meeting overall BC Hydro system requirements as cost-effectively and reliably as possible, taking into account relevant policy and operational constraints.

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[3] Also known as ICG and as the Island Cogeneration Energy Center (ICEC).

BC Hydro's obligation to serve its customers means that it plans for new electricity resources in accordance with integrated system reliability standards. The starting point is the load forecast, which considers both peak demand and annual energy requirements. The next step is to analyze existing supply. Plant additions and electricity purchases are then scheduled to minimize the expected cost of reliably meeting domestic electricity demand over the long term. This is done by building and analyzing alternative 20-year model resource portfolios of these supply options. The costs of installing and operating the energy and capacity resources in these model portfolios, minus the expected net trade revenues, are then discounted to today's dollars, and the resulting present values form the basis for comparing the relative cost-effectiveness of the various portfolios.

Government energy policy also affects both the demand for electricity and the choices available to meet the demand. BC Hydro plans in the context of that policy. In November 2002, the BC government released Energy for Our Future: A Plan for BC. The policy's four main objectives and BC Hydro's related planning objectives are as follows:

BC Government Objectives	**BC Hydro Electricity Planning Objectives**
Low electricity rates and public ownership of BC Hydro.	Minimize economic costs by establishing the least cost sequence of resources that meet customers' needs and other policy objectives.
Secure, reliable supply.	Maintain adequate dependable capacity and energy capability to meet customer needs by ensuring that industry reliability criteria are met.
Private sector development of new electricity generation.	Seek proposals from the private sector to supply power to BC Hydro.
Environmental responsibility and no nuclear power sources.	Enhance environmental responsibility through conservation and a 50% clean energy target through Power Smart, Customer-Based Generation, Green Energy and Resource Smart Programs and project proposals that meet or exceed environmental and social requirements.

The Need For New Resources

BC Hydro needs to invest in new system infrastructure in order to meet its obligation to reliably serve customers, particularly its Island customers. The reliability of electricity supply on Vancouver Island is dictated primarily by peak demand (the maximum rate of electric energy consumption) rather than energy (the amount of electric energy consumed over a period of time). Peak demand occurs in the winter, and it is this demand that is relevant to planning for reliable electricity supply.

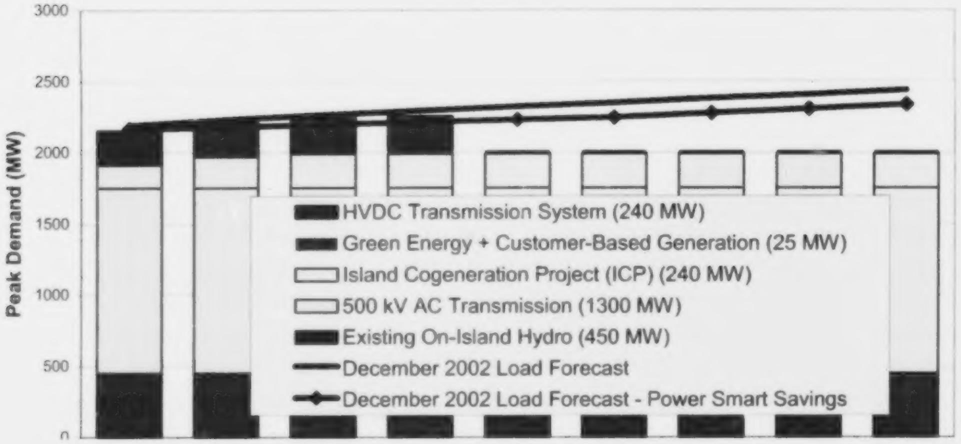
While it is important to have sufficient infrastructure to meet consumption and demand growth, a more compelling factor for Vancouver Island is the expected retirement of a significant part of the bulk transmission supply facilities that connect the Island to the Mainland. There are three separate transmission systems, supplying over two-thirds of the Island's peak demand. They consist of:

- Two 500 kV AC circuits installed in 1983-85 between Cheekye (near Squamish) and Dunsmuir (near Qualicum Bay), each with a continuous rating of 1200. The single contingency firm power transfer capacity for these circuits is the two-hour rating of 1300 MW. These circuits have on-land and subsea portions. To comply with industry reliability standards as adopted by BC Hydro, the Island requires firm supply to meet the forecast winter peak demand assuming one of these two 500 kV circuits is out of service (referred to as the single contingency or "N-1" criterion).

- Two 138 kV AC circuits installed in 1956-58 between Arnott (near Ladner) to Vancouver Island Terminal (VIT) (near Duncan). This is a subsea system across the southern part of the Georgia Strait, with on-land portions at each end and on Galiano Island and Saltspring Island. These lines have deteriorated and could fail at any time; they have zero dependable capacity for planning purposes.

- A high voltage direct current (HVDC) system installed between 1969 and 1976 from Arnott to VIT. This system lies immediately north of the 138 kV AC system but otherwise follows a similar marine and land routing. Originally rated at nearly 800 MW, this system is aging and now has dependable capacity of 168 MW. Its dependable capacity is expected to increase to 240 MW after planned cable repairs in 2003. The HVDC system is expected to be retired by 2007. After this date, the HVDC cannot be relied upon to provide firm capacity for planning purposes, but will provide useful operational flexibility for the Vancouver Island system

When forecast growth in Vancouver Island peak demand is compared to the transmission resources from the Mainland and on-Island generation resources expected to be available to meet the demand, a supply shortfall results. This shortfall is shown in the following chart.



Vancouver Island Dependable Capacity/Peak Demand Balance

The top sloped line in the chart is the December 2002 Load Forecast for Vancouver Island peak demand, measured in megawatts and accounting for transmission losses. It is based on economic and population forecasts, analysis of present and potential changes in electricity use, and historical temperatures. The line below it represents the same forecast after taking into account expected effects of BC Hydro's Power Smart program. Peak demand increases from approximately 2200 MW in 2003/04 to about 2400 MW in 2011/12. The difference in the two lines at that point—approximately 100 MW—reflects the cumulative impact of a revitalized Power Smart program, primarily in the industrial sector.[4]

The columns below the lines represent the supply components expected to be available if no new supply is developed. BC Hydro's on-Island generation resources comprise:

- a number of hydroelectric generating stations, totalling 450 MW of dependable capacity;
- the ICP, with current dependable capacity of 168 MW, expected to increase to 240 MW by the time firm gas transportation is available for the plant's full gas requirement;[5] and
- new projects from BC Hydro's Green Energy and Customer-Based Generation (CBG) programs, assumed to be capable of delivering between approximately 25 MW of dependable capacity on the Island by 2005/06.

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[4] The key focus of Power Smart, though, is energy savings rather than peak demand reduction.

[5] Will require upgrades to the Centra Gas Inc. pipeline or construction of the Georgia Strait Crossing Pipeline, as discussed in this application.

For planning purposes, these on-Island resources can supply roughly one-third of the Island's peak demand. The rest of it is met by Mainland-based generation and transmission to the Island. As the chart shows, more than half of the Island's demand is met by Mainland generation delivered to the Island over the 500 kV AC transmission system.

The remaining transmission component in the supply/demand chart represents supply available from the HVDC system. The key issue is the increasing unreliability of the HVDC system over time as it nears its expected retirement While BC Hydro has determined that it would be prudent to invest in further refurbishment of the HVDC system to gain operating flexibility, it is increasingly risky to continue to rely for firm capacity on an aging and deteriorating system that could fail without warning. While no one can predict with confidence when the HVDC system will fail, BC Hydro does not rely upon it for planning purposes past 2007. As the chart shows, this will result in the loss of about 240 MW of dependable capacity.

The essential conclusion is that new infrastructure investment is needed to ensure the continuity of reliable supply to Vancouver Island.

Resource Options and Portfolio Analysis

In preparing for this application, BC Hydro identified the basic options and constructed three alternative 20-year portfolios from those options to determine which of the portfolios offered the least cost way of meeting Vancouver Island's electricity needs in compliance with reliability standards.

- Various generation and transmission options were considered with a view to supplying the capacity shortfall. Under BC Hydro's approach to electricity planning, these options were modeled as 20-year resource portfolios and in turn analyzed for cost-effectiveness by comparing the net present value (NPV) of their cost. The following portfolios were modelled:
    - Portfolio 1, referred to as "VIGP Only" because it does not include future on-Island gas generation within the portfolio horizon;
    - Portfolio 2, "On-Island CCGTs," so called because it does include other combined-cycle combustion turbines on Vancouver Island after the VIGP; and
    - Portfolio 3, called "Mainland Generation" because it does not include the VIGP or future CCGTs on the Island, but relies solely on generation that takes place on the Mainland.

The following table summarizes the NPV of costs net of trade revenues, discounted at 8% and stated in 2002 dollars, of the three portfolios. It also compares Portfolios 2 and 3 to Portfolio 1.

Portfolio 1 VIGP Only	Portfolio 2 On-Island CCGTs	Portfolio 3 Mainland Generation	Portfolio 2 minus Portfolio 1	Portfolio 3 minus Portfolio 1
9,677	9,525	9,687	-152	10

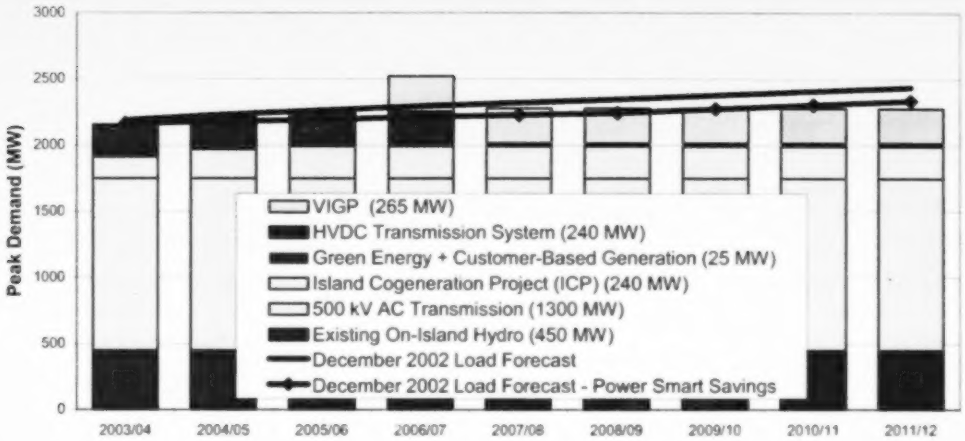
NPV Cost of Portfolios 1-3 ($ millions; 8% Real Discount Rate)

The NPV Costs of Portfolios 1 and 3 are almost identical. However, Portfolios 1 and 2 provide reliability sooner and Portfolio 3 does not include the possible cost of mitigating the risk of a shortfall in Vancouver Island firm supply before the in-service date of new transmission. Portfolio 2, with future on-Island gas generation, is the least cost portfolio. However, because Portfolio 1 has approximately the same NPV Cost as Portfolio 3, future on-Island gas generation is not required to justify the VIGP.

Further, the VIGP addresses the Island's immediate reliability concern, allowing time for Island customers, particularly industrial customers, to pursue Power Smart or customer-based generation and for the consideration of other options. The VIGP also provides diversification of electricity and gas supply to Vancouver Island and delays the need for Interior-to-Lower Mainland bulk transmission additions.

Based on the analysis summarized above and outlined in detail in this application, the VIGP and other supply-side and demand-side options complement, rather than compete, with each other to reliably meet the Island's electricity needs. This reflects the use of generation closer to a load centre to address a regional supply problem.

A key contribution of the VIGP lies in filling the gap created by the expected retirement of the HVDC system. The following chart, which adds a component to the supply columns for the additional dependable capacity expected from the VIGP, shows how the VIGP helps defer the need for further resources and increases planning flexibility for developing future supply-side and demand-side options.



Vancouver Island Dependable Capacity/Peak Demand Balance With VIGP

Project Facilities and Design

The VIGP comprises a CCGT plant having a base power output of 265 MW without duct firing and a peak power output of 295 MW with duct firing; a service line to supply the plant with natural gas from Centra Gas Inc. (Centra); a water supply line; a line to transport wastewater to an existing treatment system on the Harmac site, an upgrade to transmission circuits in the Duke Point area; and related works.

The plant is designed to convert about 55% of the lower heating value (LHV) of natural gas into electricity,[6] a high efficiency achievable by using advanced technology that generates additional electricity from hot turbine exhaust gases. It is not a cogeneration plant serving both an electrical and a thermal load because, after investigation, VIEC concluded that there was no feasible thermal host on Vancouver Island.

The Duke Point site for the proposed plant was selected after a review of site options on Vancouver Island. It lies far from residential areas, is zoned for industrial use and is compatible with neighbouring industry, is cleared from past development, and has favourable geotechnical conditions. The site is close to the Centra pipeline and the Vancouver Island transmission system. It scored the highest in the site evaluation process, in large part due to the reduced amount of development and lower environmental impacts that would result from using existing water supply and wastewater treatment infrastructure at the site.

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[6] Heating value is a measure of the energy released when a fuel is burned. Higher heating value (HHV) includes the heat released when water produced by combustion of the fuel condenses. LHV excludes the heat released by condensing water. For natural gas, LHV is about 90% of HHV.

An advanced, dry low NO_x (and low CO) GE 7FA combustion turbine generator (CTG) will be used to carry out the combustion of natural gas, converting its latent energy into mechanical energy to drive both the electric generator and the combustion turbine compressor. Air needed by the CTG is supplied through ductwork to the turbine's compressor and injected with natural gas into a combustor under carefully controlled conditions and ignited. The gases produced expand through the turbine, generating the mechanical energy for the generator and air compressor. This technology became available in the late 1980s and has since been developed to achieve highly reliable performance and low emission levels.[7]

Project Costs, Revenue Requirements and Cost of Service

Of the project's expected $340 million capital cost (2002 dollars), approximately $69 million has been spent to date on turbine equipment, land acquisition, regulatory and other costs. A further $27 million in committed expenditures brings the project's total direct committed costs to approximately $96 million as of the end of February 2003.

Following the announcement of the government's energy policy, VIEC decided to limit further commitments to project expenditures until all the relevant regulatory approvals have been received. Further spending will be limited to meeting payments under equipment supply contracts for the combustion turbine generator, costs to store equipment until delivery to the site, costs to complete regulatory and consultation processes, and project administration. This decision has resulted in revising the VIGP's in-service date target to July 2006.

The project's cost of service is summarized in the following table.[8]

	2006/07	2007/08	2010/011	2015/16	2020/21	2025/26	2030/31	2031/32
OMA	13	18	18	20	22	25	27	7
Gas Commodity	60	82	87	96	106	117	129	32
Gas Transportation	41	27	27	27	27	27	27	7
Motor Fuel Tax	4	6	6	7	7	8	9	2
Capital Charge	21	28	28	28	28	28	28	7
Total Cost of Service (Nominal Dollars)	**139**	**161**	**166**	**177**	**189**	**204**	**219**	**55**
Total Cost of Service (2002 Dollars)	**108**	**143**	**139**	**135**	**131**	**127**	**124**	**31**

Cost of Service ($Millions) for the VIGP 2007-2032

This application is filed without an analysis of the rate impact of the VIGP because that analysis is related to BC Hydro's application to the Commission on its Heritage Resources, which it expects to file in April 2003. VIEC plans to file the rate impact analysis for the VIGP at that time. VIEC considered it prudent to file this application now and provide the rate impact analysis later in view of the time constraints to meeting a 2006 in-service date for the VIGP.

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[7] See discussion in section 6.8.1 and Appendices E - G.

[8] 2006/7 and 2031/32 are partial years.

Other Approvals and Applications

The VIGP is integrally linked with the proposed Georgia Strait Crossing Project (GSX Project), involving the design, construction and operation of a new natural gas pipeline from the market hub at Sumas, Washington to Vancouver Island. The pipeline will permit natural gas purchased at Sumas to be transported to markets in northwestern Washington state and the Island. The GSX Project is subject to concurrent federal regulatory approvals in Canada and the United States. The US approvals have already been obtained. Canadian approvals are pending at the date of this application. The VIGP will only proceed if the GSX Project proceeds.

The City of Nanaimo and the Association of Vancouver Island Coastal Communities have each passed resolutions supporting the GSX Project and the VIGP as being, in principle, the best means for the Island to secure a reliable and independent electricity supply for its residential, agricultural, tourism, technology, commercial and industrial sectors.

As already noted, VIEC has also filed the EAO Application, which includes an integrated assessment of the project's social, economic, health, cultural and First Nations impacts. A ministerial decision on the granting of an environmental assessment certificate for the VIGP is expected by June 2, 2003. VIEC has conducted extensive public consultation in the context of the EAO Application and continues to do so. The rights of way to be used by the VIGP for the on-Island transmission upgrade lie within the territory of the Snuneymuxw First Nation (SFN). VIEC has developed and is carrying out a specific consultation program with the SFN in regard to the land usage.

VIEC will apply to the appropriate agencies for all other approvals, permits and licences required before building and operating the VIGP.

Conclusions

The reliability of Vancouver Island's electricity supply is at risk because of the expected retirement of the Arnott-VIT HVDC transmission system. The VIGP is the most well-developed option to address the reliability concerns, and it does so cost-effectively and in the required time frame. The "VIGP-Only" portfolio is comparable in cost to the alternative of Mainland generation combined with transmission to the Island; it reduces the timing risk associated with the HVDC system reaching its expected retirement; and it increases BC Hydro's planning flexibility for acquiring resources at least cost, including future generation options on the Island.

These attributes are summarized in the following table, which again sets out the government policy and electricity planning objectives summarized earlier and applies them to the VIGP.

BC Government Energy Policy	BC Hydro Electricity Planning Objectives	Applying the Objectives to the VIGP
Low electricity rates and public ownership of BC Hydro.	Minimize economic costs by establishing the least cost sequence of resources that meet customers' needs and other *policy objectives*.	The VIGP is one of the least cost alternatives to Vancouver Island's capacity needs, and does so with the greatest construction cost certainty. With GSX it has significant option value for pursuing future Island generation.
Secure, reliable supply.	Maintain adequate dependable capacity and energy capacity to meet customer needs by ensuring that industry reliability criteria are met.	The VIGP will reduce the risk of inadequate reliable electrical capacity for Vancouver Island sooner and with the greatest timing certainty. Reliability is of particular concern given the expected retirement of the HVDC system.
More private sector opportunities.	Seek the private sector to provide proposals to supply power to BC Hydro.	There will be private sector involvement in the design, construction and operation of the VIGP whether the project is sold to an IPP, as is expected or operated for VIEC under contract.
Environmental responsibility and no nuclear power sources.	Enhance environmental responsibility through conservation and a 50% clean energy target through Power Smart, Customer Based Generation, Green Energy and Resource Smart Programs and by project proposals that meet or exceed environmental and social requirements.	The VIGP will be one of the cleanest natural gas-fired generation facilities in North America, and its 2006 in-service date will facilitate the consideration and development of Power Smart, Customer Based Generation, Green Energy and Resource Smart Programs to supply dependable capacity to Vancouver Island.

1 Applicant Information and Project Background

1.1 *Name, Address and Nature of Business*

Vancouver Island Energy Corporation (VIEC) is a wholly-owned subsidiary of British Columbia Hydro and Power Authority (BC Hydro), a provincial corporation established in 1962[9] and continued under the *Hydro and Power Authority Act.*[10] BC Hydro's head office is located at 333 Dunsmuir Street, Vancouver BC.

BC Hydro generates, transmits and distributes electricity to approximately 1.6 million customers in an area comprising about 94% of BC's population. The Vancouver Island Generation Project (VIGP) proposed by VIEC and BC Hydro consists of a natural gas-fired electric generating plant and related works intended to serve domestic electricity needs. The VIGP will generate electricity in a high-efficiency combined-cycle gas turbine (CCGT) plant. The electricity so produced will become part of BC Hydro's resource base to meet its customers' electric load—in particular, its load on Vancouver Island and the Gulf Islands (collectively referred to as "Vancouver Island" or "the Island").

1.2 *Nature of Application*

By section 32(7) of the *Hydro and Power Authority Act*, BC Hydro is subject to regulation under the *Utilities Commission Act.*[11] Under the provincial government's new energy policy released in November 2002, the British Columbia Utilities Commission (BCUC or Commission) is to review the VIGP to determine if it is the most cost-effective means to reliably meet Island power needs. Accordingly, VIEC submits this application for a certificate of public convenience and necessity (CPCN) for the construction and operation of the VIGP, pursuant to sections 45 and 46 of the *Utilities Commission Act*.

1.3 *Names, Titles and Addresses Of Contacts for this Application*

Project Manager:	Legal Counsel:	Copy communications to:
Mr. Lachlan Russel	Mr. Brian J. Wallace, QC	Alice Ferreira
Vancouver Island	Lawson Lundell	Regulatory Affairs
Generation Project	Barristers and Solicitors	BC Hydro
6911 Southpoint Drive E14	1600 - 925 W. Georgia St.	333 Dunsmuir Street D17
Burnaby BC V3N 4X8	Vancouver BC V6C 3L2	Vancouver BC V6B 5R3
Tel: (604) 528-2661	Tel: (604) 631-9225	Tel: (604) 623-4046
Fax: (604) 528-3037	Fax: (604) 669-1620	Fax: (604) 623-4111

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[9] BC Hydro was created as the successor, by amalgamation, of the British Columbia Electric Company Limited and the British Columbia Power Commission, previously the two major suppliers of electricity in BC.

[10] R.S.B.C. 1996, c. 212.

[11] R.S.B.C. 1996, c. 473, except for ss. 50, 51(c), 52, 57(2), 95 and 98, from which BC Hydro is exempt.

1.4 *Applicant's Financial, Managerial, and Technical Capacity*

1.4.1 Financial Capacity

BC Hydro is an agent of Her Majesty the Queen in right of the Province of British Columbia. The Minister of Finance and Corporate Relations is BC Hydro's fiscal agent, and BC Hydro may borrow money only with the approval of the Lieutenant-Governor in Council, and then only up to amounts authorized by the Legislature.

BC Hydro has constructed some of the largest projects in the province undertaken by a single corporation and has the financial capacity to do so by several means: borrowing guaranteed by the province; borrowing directly from the province; and using funds generated internally from the operation of its business. Moody's Investor Service and Standard & Poor's Corporation, two major financial rating agencies in the United States, have rated BC Hydro bonds as Aa2 and AA- respectively. The rating from the Dominion Bond Rating Service in Canada is AA (low).

1.4.2 Managerial and Technical Capacity

VIEC's officers and directors are also officers of BC Hydro, whose board of directors is appointed by the Lieutenant-Governor in Council. Since 1962, BC Hydro has planned, designed, and built electric generation, transmission and distribution facilities. It has the relevant expertise to carry out a project of this scope.

VIEC was originally formed to facilitate BC Hydro's participation in a joint venture to develop the VIGP and to separate the joint VIGP assets and liabilities from those of BC Hydro. When the joint venture was terminated (see discussion in section 1.5), BC Hydro determined that it would be beneficial to keep VIEC so as to facilitate the ultimate sale of the power plant to the private sector.

VIEC intends to offer the VIGP plant for sale to a qualified independent power producer (IPP) either before or after construction starts. Accordingly, VIEC seeks a certificate that confirms the public convenience and necessity for the VIGP, whether the project is completed by VIEC or by an IPP. If VIEC, rather than an IPP, takes responsibility for constructing and operating the VIGP, VIEC will contract the project's engineering, procurement, and construction management (EPCM) to a qualified engineering contractor and will contract its operations to a qualified operator.

1.5 *Project Background*

This section sets out the VIGP's background, starting with the provincial government's 1996 directive to negotiate the long-term purchase of electricity from a cogeneration plant proposed for and subsequently built on the Island, up to the recent hearing for the proposed Georgia Strait Crossing Pipeline (the GSX Project) and this CPCN application.

1.5.1 IPP Review Panel and the Island Cogeneration Project (ICP)

The genesis of the VIGP dates back to the mid-1990s. In 1994, the provincial government sought supply-side and demand-side proposals to meet the province's increasing electricity demands, including those on Vancouver Island. It asked BC Hydro to issue a Request for Proposals (RFP) to IPPs to supply electricity within British Columbia.

A number of proposals were received and reviewed by a panel, the Independent Power Producers' Review Panel (IPP Review Panel), using a Multiple Account Evaluation (MAE)[12] process.[13] For details, see Appendix B. After the MAE was completed, the provincial government directed BC Hydro to negotiate an electricity purchase agreement (EPA) with the proponents of the proposed 240 MW Island Cogeneration Project (ICP) in Campbell River. The government thereby determined that the preferred means of providing for Vancouver Island's electricity needs was through on-Island gas-fired generation.[14] Under the EPA, BC Hydro is responsible for supplying gas to the project. The ICP achieved commercial operation in 2002.

1.5.2 Port Alberni Generation Project

The IPP Review Panel identified the Port Alberni Cogeneration Project (PACP) as the second project that should be built in pursuit of the Island gas generation strategy. In a July 1997 letter, the Minister of Employment and Investment directed BC Hydro to develop PACP as well, and to enter into commercial negotiations with PACP for an EPA that would maximize benefits to the province and to BC Hydro. The project was to be a joint venture between ATCO Power (formerly CU Power) and Pan Canadian Petroleum.

The parties signed a Key Principles Agreement in 1998 and PACP received an EAO project approval certificate in December 1999. The PACP was to have been exempt from Part 3 and section 71 of the *Utilities Commission Act* by Ministerial order.[15] That order, which applies to IPPs selling all or part of their output to BC Hydro, meant that the PACP would have been built without a CPCN. But BC Hydro and the project proponents could not reach a mutually acceptable commercial agreement, and the PACP came to an end in February 2000. BC Hydro then sought proposals for a joint venture partner to build and operate a CCGT in Port Alberni, renamed the Port Alberni Generation Project (PAGP). By letter of May 18, 2000, the government confirmed the direction to BC Hydro to continue pursuing development of the PAGP.

BC Hydro's January 2000 update to its Integrated Electricity Plan (IEP Update), issued prior to the conclusion of the PACP negotiations, showed the PACP and associated gas pipeline infrastructure as committed resources scheduled to be in service in 2003.[16] The IEP Update also indicated that Vancouver Island had emerged as the preferred site for further major resource additions. It identified significant cost savings associated with an additional CCGT on the Island by 2007 to meet system requirements and to avoid the cost of replacement transmission to the Island.

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[12] A framework developed to aid identification and evaluation of financial, customer service, environmental, social and economic development impacts as part of a decision-making process. See *Multiple Account Evaluation Guidelines* (Province of British Columbia, Crown Corporations Secretariat: February 1993).

[13] J. Allan *et al*, *Report of the Independent Power Producers Review Panel* (August 1996).

[14] See affidavit of Paul Weiringa at Appendix B.

[15] Minister's Order M-22-9801 (August 28, 1998) and Amending Order M-22-9801-A (March 30, 2000).

In October 2000, BC Hydro selected Calpine Canada Power Holdings Ltd. (Calpine Canada) as the partner with whom it would negotiate a joint venture agreement to develop the PAGP. BC Hydro worked with Calpine Canada to address the needs of the community and the proponent. BC Hydro was to buy the plant's total output under a 25-year EPA. The companies reached an interim agreement in October 2000 and jointly committed to buying a gas turbine from General Electric (GE) and a Fuji Electric steam turbine from Sumitomo Corporation of America (Fuji), both for delivery in the fall of 2002.

On December 18, 2000, the Minister of Employment and Investment exempted BC Hydro and the project proponents from the need to apply for a CPCN for the Port Alberni plant.[17] In May 2001, BC Hydro and Calpine Canada jointly applied to the EAO for a project approval certificate. However, that application was withdrawn when Port Alberni's municipal council refused rezoning of the site selected for the plant.

1.5.3 VIEC as Project Developer

VIEC was subsequently incorporated as a wholly-owned subsidiary of BC Hydro, formed to partner with Calpine Canada to develop the project at a new site. BC Hydro and VIEC renamed the project as the Vancouver Island Generation Project (VIGP) and targeted an in-service date of November 2004 in order to meet peak demand in the winter of 2004/05 and onward. However, joint venture negotiations ceased in May 2002, after which VIEC decided to continue developing the VIGP and to supply the electricity to BC Hydro to meet domestic requirements. Due to the intervening time lapse and the estimated time needed to complete all regulatory approval processes, VIEC revised the expected in-service target date to November 2005.

1.5 4 Decision to Use a Stand-Alone (Non-Cogeneration) CCGT

In the original PACP proposal, the steam requirements for the mill associated with that proposal were to be met in part by steam provided by the CCGT. The CCGT would have been located in the mill facilities, in an area where older facilities had been decommissioned. Other cost and management benefits were expected from joint use of mill facilities, and mill personnel would have operated the CCGT once it reached commercial operation. After the PACP negotiations ceased, BC Hydro investigated opportunities for cogeneration directly with the mill in Port Alberni while looking for a joint venture partner. That investigation led to the conclusion that building a cogeneration project would not meet the business objectives of the joint venture or the mill. Hence BC Hydro pursued a stand-alone CCGT, with appropriate preliminary design.

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[16] *Integrated Electricity Plan: An Update to the 1995 IEP* (BC Hydro, January 2000), page iii, Table 1.

[17] Order No. M-22-0002.

When Port Alberni's municipal council refused zoning for the proposal, BC Hydro and VIEC reviewed potential steam hosts at Crofton and Duke Point. No opportunities were identified in which a thermal host could enable the design and commissioning of a commercially viable cogeneration plant. Thus the decision was made to continue with a stand-alone (non-cogeneration) CCGT.

1.5.5 Further Government Direction

Pursuant to the provincial government's November 2002 energy policy, BC Hydro and VIEC prepared this application to assist the Commission in reviewing the VIGP to ensure that it is the most cost-effective means of reliably meeting the Island's electricity needs.

1.5.6 Equipment and Other Project Costs Incurred to Date

Due to the revised VIGP scheduling, VIEC negotiated a five-month deferral of the Fuji steam turbine delivery and a one-year deferral of the GE gas turbine delivery. When the project was relocated from Port Alberni to Duke Point, warranty extensions were also negotiated to match the delay in the estimated commercial operation date, from November 2003 to November 2004. Fuji has so far been unwilling to further extend the warranty provisions, but negotiations with GE are ongoing. The new delivery dates are March 2003 and September 2003, for the steam turbine and gas turbine, respectively.

VIEC has paid 64% of the $63.7 million gas turbine cost and all of the $22.6 million steam turbine cost, not including storage and handling. Table 1 summarizes the direct costs incurred on the project, as well as the associated costs to which BC Hydro has committed as of February 28, 2003.[18]

Item	Amount Spent	Amount Committed[19]
GE Gas Turbine	$39.2	$63.7
Fuji Steam Turbine	23.3	24.9
Regulatory	4.7	5.3
Transmission Study	0.1	0.3
Land Acquisition	1.5	1.5
Total Direct Unloaded Costs	**$68.8**	**$95.7**

Table 1: Direct Costs Incurred on VIGP as of February 2003 ($ Millions)

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[18] The costs in Table 1 do not include interest during construction or allocation of corporate overhead.

[19] Includes **Amount Spent**.

Following the announcement of the government's energy policy in late 2002, VIEC decided to make no further commitments to VIGP project expenditures until regulatory approvals have been received for both the VIGP and the GSX Project. Further spending will be limited to meeting payments under the equipment supply contracts for the combustion turbine generator; costs to store the equipment until delivery to the site; and costs to complete the required regulatory and consultative processes, including those related to addressing relevant First Nations interests. This decision has resulted in revising the VIGP's in-service date target to July 2006.

1.5.7 Relationship of the VIGP to the Georgia Strait Crossing (GSX) Pipeline

The VIGP will require gas from the GSX Project, which involves the design, construction and operation of a new natural gas pipeline from the market hub at Sumas, Washington to Vancouver Island. BC Hydro has incurred costs of approximately $46 million to date on the GSX Project. The pipeline, which is subject to concurrent federal regulatory approvals in Canada and the US,[20] will permit natural gas purchased at Sumas to be transported to markets in northwest Washington State and Vancouver Island.

1.5.8 Sunk Costs

As already noted, the VIGP and the GSX Project are linked investment decisions. If these projects do not proceed, BC Hydro's sunk costs for the projects are expected to be approximately $60 million for the VIGP and approximately $55 million for the GSX Project,[21] for a total in the range of $110 million to $120 million. These estimates include amounts spent to date and projected commitments until the end of October 2003.[22]

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[20] See section 9.1.

[21] Includes engineering, environmental and geotechnical studies; preparation of contracts; insurance and analysis of tenders, regulatory processes; project management; and acquisition of easements.

[22] BC Hydro estimates it will have decisions by October 2003 on both this application and the CPCN application for the GSX Project. See Figure 13 at page 76.

2 BC Hydro System Overview

VIEC's application is made in the context of planning for the BC Hydro system as a whole. This section provides an overview of that system and sets out some key concepts and terms that are fundamental to the application. Technical terms are italicized when they are first introduced and are collected in the glossary at Appendix A.

2.1 *The Electric Generation System*

BC Hydro, one of Canada's largest electric utilities, delivers electricity mainly through an interconnected or *integrated* system of more than 75,000 kilometres of transmission and distribution lines. Some customers live in areas too remote to be served by transmission lines; these *non-integrated* communities have traditionally been served with electricity generated by local diesel and gas turbines or small hydroelectric stations.

2.1.1 Hydroelectric Stations

Most of the power generated by BC Hydro is produced by major hydroelectric stations on the Columbia and Peace rivers. Large *storage dams* at these facilities hold water in reservoirs for use throughout the year, in contrast to *run-of-river* dams that operate using the *streamflow* of a river rather than reservoir flow. In both types of facilities, the energy of the falling water causes *turbines* to rotate, which in turn drive *generators* that convert mechanical energy into electric energy. BC Hydro has 30 hydroelectric generating stations (GS), 29 of which are in the integrated system.

2.1.2 Thermal Stations

BC Hydro also owns three thermal generating stations, which burn fuel to produce hot gases or steam to drive turbines connected to generators. The largest of these is Burrard GS, a natural gas-fired conventional steam turbine station in the Lower Mainland. It is part of the integrated system. BC Hydro also owns two small combustion turbine stations: Prince Rupert GS, which uses natural gas as a primary fuel and diesel as a backup; and Fort Nelson GS, which runs only on natural gas. Keogh GS, a diesel-fired combustion turbine station built in the 1970s near Port Hardy on Vancouver Island, was recently decommissioned.

2.1.3 Electricity Purchase Agreements with IPPs and Others

As well as generating its own electricity, BC Hydro buys electricity from *independent power producers* (IPPs) under *electricity purchase agreements* (EPAs). BC Hydro has approximately two dozen long-term contracts with existing and operational natural gas, biomass, or small hydro IPPs. BC Hydro also purchases electricity from Alcan under the terms of the Long Term Energy Purchase Agreement (LTEPA). So far, EPAs have generally been for projects in which BC Hydro pays for the contracted energy but does not control how much energy is generated at any particular time. These projects are referred to as *non-dispatchable* contracts. The energy and capacity capabilities of these resources are summarized in Table 2. Following its April 2000 call for Green Energy projects, BC Hydro signed additional EPAs, primarily with small hydro IPPs, although the majority of the associated projects are not yet in commercial operation. This initiative and BC Hydro's other resource acquisition activities are described in section 3.3.

2.1.4 System Capacity and Energy Capability

Two concepts essential to understanding the electric system in general, and this application in particular, are *capacity* and *energy capability*. Capacity is the rate at which the electric system or a generating unit is able to produce or transmit energy, typically measured in megawatts (MW). Energy capability is the amount of energy that can be generated by the electric system or a generator over a period of time under specified conditions. It is typically measured in megawatt-hours (MWh)[23] or gigawatt-hours (GWh).[24] One gigawatt-hour can serve about 100 residential customers for a year. Similarly, customer *demand* for electricity is measured in MW, since it is the amount of energy required at a given time, while *consumption* is measured in MWh or GWh, as it represents energy used over a period of time.

The capacity of an electric system or its generators varies due to such things as water availability and streamflow (for hydroelectric generation) or firm supply of fuel (for thermal generation). Several related terms are commonly used:

- ☐ *nameplate capacity* (may also be referred to as installed capacity): the maximum output of a generating unit under specified conditions, as stated by the manufacturer;
- ☐ *maximum capacity*: the maximum output that is observed in practice; and
- ☐ *dependable capacity* (may also be called firm capacity): the maximum output that can be reliably supplied coincident with the system peak load, taking into account the physical state and availability of the equipment, and on water or fuel constraints.

Since peak demand occurs in the winter, the relevant definition of dependable capacity reflects that fact: it is the maximum capacity that a plant or unit can reliably provide during the peak weekday load for two continuous weeks of cold weather. Similarly, the dependable capacity rating of a gas-fired plant is defined with reference to its capability to generate, which in turn depends on access to a firm gas supply. A plant's annual energy capability also depends on such things as the total quantity of water available during the year, regularity of stream flow, and fuel availability.

Table 2 depicts these relationships for the major components of energy supply, after the anticipated completion of a fourth generating unit at BC Hydro's Seven Mile dam and powerhouse on the Pend d'Oreille River ("Seven Mile Unit 4"). The table shows that by 2004 the annual energy capability of BC Hydro's owned and contracted resources on the integrated system will be approximately 55,300 GWh; the dependable capacity, approximately 11,400 MW.

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[23] One thousand kilowatt-hours (kWh).

[24] One million kilowatt-hours.

Resource	**Annual Firm Energy Capability (GWh)**	**Dependable Capacity (MW)**
Hydroelectric	43,300[25]	9,750[26]
Thermal	6,280	958[27]
Existing Purchase Agreements:		
Alcan[28]	1,225	147
Arrow Lakes[29]	750	120
IPPs	3,720[30]	450[31]
Totals	**55,275 GWh**	**11,425 MW**

Table 2: Firm Energy Capability and Dependable Capacity of BC Hydro System

2.1.5 Electricity Trade

BC Hydro's subsidiary, Powerex Corp., trades in electricity in the western North American wholesale electricity market. Electricity trade helps BC Hydro optimize its system resources, improves the security and reliability of electricity supply for the province, and provides significant economic benefits. Electricity trade is possible because BC Hydro's bulk transmission network is interconnected with utilities in Alberta and the US. This transmission network links BC Hydro to a large market for the purchase and sale of wholesale electricity outside the province.

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[25] Firm energy capability of the hydroelectric system equals its annual energy capability under the period of lowest historical stream flow conditions. It includes Resource Smart activities to date.

[26] Includes Seven Mile Unit 4 (90 MW) and Resource Smart activities to date. Dependable capacity for large hydro installations is based on an 85% confidence level over a range of historical stream flow conditions.

[27] Dependable capacity includes consideration of firm gas supply (transportation).

[28] Delivered under the long-term energy purchase agreement (LTEPA) with Alcan.

[29] EPA with Columbia Power Corporation and Columbia Basin Trust to purchase output of Arrow Lakes GS (190 MW).

[30] Based on EPAs.

[31] 400 MW of this total dependable capacity is attributable to two natural gas IPP plants (McMahon — 105 MW and ICP— 240 MW) and one biomass generation plant (NW Energy — 55 MW). The ICP is currently rated at 164 MW of dependable capacity based on the amount of firm gas transportation available from Centra Gas.

The flexibility of BC Hydro's predominantly hydroelectric generating system enables Powerex to purchase electricity from the market when prices are lower and sell electricity to the market when prices are higher. Powerex buys electricity from outside the BC Hydro system to meet its own trade commitments and to support BC Hydro's domestic needs when advantageous to do so. In the last two fiscal years, Powerex has been a net purchaser of electricity. These purchases are made from other producers in BC, Western Canada and the US.

2.1.6 System Constraints and Operations

BC Hydro's generation system also incorporates a number of power and non-power operations not directly tied to electricity production. Power-related requirements may require the operation of specific plants at specific times. For example, Burrard GS and other projects may have to operate to maintain system voltages, alleviate transmission congestion or meet local area needs. Non-power requirements related to flood control, water supply, water transport, recreation, aquatic and terrestrial habitats, and safety may also impact operations. Water licences, for instance, can require flow releases to maintain fish habitats; and flood control plays a key role in the Columbia River Treaty, the Canada-US agreement that regulates the Columbia River for both electricity production and flood management.

2.2 *The Transmission and Distribution Systems*

2.2.1 Transmission

The energy produced by BC Hydro's generating stations or purchased from IPPs and neighbouring utilities is carried to load centres by the *bulk transmission* network. Since most of BC's load centres are located far from major generating sites, these lines operate at high voltage to reduce line losses over the distance that electricity must travel; the voltage increase is accomplished by using 'step up' transformers at the generating sites.[32]

Transmission voltages are generally considered to be anything over 60,000 volts (60 kV). BC Hydro's bulk transmission lines operate at 500 kV. These voltages are too high for even the largest electricity users, so transmission substations, are used to 'step down' the voltage to 230 kV or 138 kV transmission, sometimes referred to as subtransmission system. BC Hydro's bulk 500 kV transmission system, and the major generating stations to which it is connected, is depicted in Figure 1.[33]

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[32] When electric current flows through a conductor, heat is generated in rough proportion to the square of the current. The amount of power transmitted equals the product of voltage and current. Thus the most efficient way to transmit bulk power is at high voltage and low current, resulting in much lower heat loss.

[33] From *Making the Connection*, 2nd Revision (BC Hydro, April 2000).

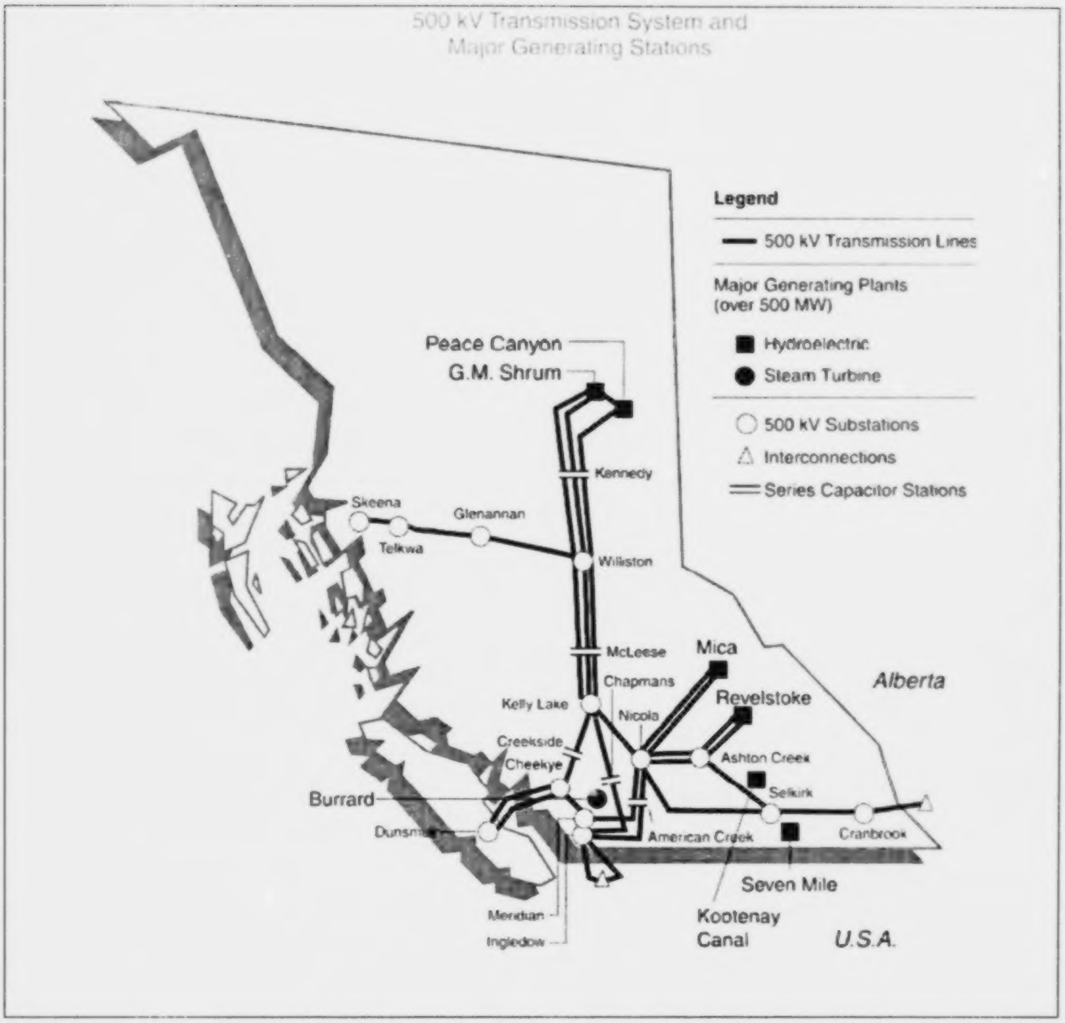
500 kV Transmission System and
Major Generating Stations
Legend
500 kV Transmission Lines
Major Generating Plants (over 500 MW)
■ Hydroelectric
● Steam Turbine
○ 500 kV Substations
△ Interconnections
═ Series Capacitor Stations
Peace Canyon
G.M. Shrum
Kennedy
Skeena
Telkwa
Glenannan
Williston
McLeese
Mica
Chapmans
Alberta
Kelly Lake
Revelstoke
Nicola
Creekside
Cheekye
Ashton Creek
Burrard
Selkirk
Dunsmuir
American Creek
Cranbrook
Seven Mile
Meridian
Ingledow
Kootenay Canal
U.S.A.

Figure 1: **BC Hydro 500 kV Transmission System and Major Generating Stations**

Most of BC Hydro's transmission network delivers electricity by *alternating current* (AC). However, *high voltage direct current* (HVDC) transmission is used where it has been more economic. Although HVDC transmission lines and submarine cables are lower cost than AC lines or cables that carry the same power, expensive converters are required at the line terminals to connect the HVDC system to the AC power system.

In the case of submarine cables, the technical feasibility and economics of HVDC versus AC depends on the power transfer capacity requirements and the length of the submarine cable crossing. There are technical restrictions on AC for long submarine cable circuits because of the associated high cable charging currents—the capacitive characteristics of AC cable. Therefore, for long crossings, HVDC may offer the only technically viable option.

For instance, the critical distance when the 500 kV AC cable circuits to Vancouver Island were constructed was approximately 45 km. At that distance the cable charging or *reactive power* flow alone would reach the thermal rating of the 500 kV cables, leaving no room for any *true power* flow. The interposition of Texada Island between the Mainland and the Island allowed the AC cable crossing to be divided into two crossings for the 500 kV Malaspina-Dunsmuir circuits, the 9 km Malaspina Strait crossing and the 30 km Georgia Strait crossing. This allowed *reactive compensation* equipment to be installed on Texada Island to manage the cable charging problem.

2.2.2 Distribution

Some large industrial customers can accept electricity at transmission voltages. About one-third of BC Hydro's domestic sales are made to such "transmission customers." But for most purposes, the voltage needs to be reduced even more at distribution sub-stations, for distribution to commercial and residential customers and smaller industrial customers.

3 BC Hydro's Approach to Electricity Planning

3.1 *Overview*

As a regulated utility with an obligation to serve its customers with a high degree of reliability, BC Hydro plans for new electricity resources in the context of integrated system reliability standards, taking into account transmission impacts and regional requirements.

BC Hydro's electricity plans and planning processes are also shaped by provincial government policies and directives, changing market structures and conditions, and electricity technology developments. Key energy policy considerations and electricity planning criteria are summarized below. The historical policy and planning considerations for the VIGP are presented in section 1.5.

The starting point for electricity planning is the Electric Load Forecast, BC Hydro's best estimate of peak demand and annual energy requirements for the next 20 years. It is revised in December of each year, and this application relies on BC Hydro's December 2002 Electric Load Forecast, discussed in chapter 4. The next step, and for this application the more significant one, is to analyze existing supply. Supply-side and demand-side activities are then scheduled so as to try to minimize the expected cost of reliably meeting electricity needs. BC Hydro does this by analyzing alternative 20-year resource portfolios for meeting the forecast demand and energy requirements.

3.2 *Government Energy Policy*

On November 25, 2002, the BC Government released its new energy policy.[34] The four main policy objectives are:

- ☐ low electricity rates and public ownership of BC Hydro;
- ☐ secure, reliable supply;
- ☐ more private sector opportunities; and
- ☐ environmental responsibility and no nuclear power sources.

Table 3 shows how BC Hydro's electricity planning objectives align with government policy.

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[34] *Energy for Our Future: A Plan for BC*, Ministry of Energy and Mines (November, 2002). The full text of the policy is available on the government's website at www.gov.bc.ca/em/popt/energyplan.htm.

BC Government Objectives	**BC Hydro Electricity Planning Objectives**
Low electricity rates and public ownership of BC Hydro.	Minimize long-term economic costs by establishing the least cost sequence of resources that meet customers' needs and other policy objectives.
Secure, reliable supply.	Maintain adequate dependable capacity and energy capability to meet customer needs by complying with electric industry reliability criteria.
Private sector development of new electricity generation.	Seek proposals from the private sector to supply power to BC Hydro.
Environmental responsibility and no nuclear power sources.	Enhance environmental responsibility through conservation and a 50% clean energy target through Power Smart, Customer Based Generation, Green Energy and Resource Smart Programs and by proposing projects that meet or exceed environmental and social requirements.

Table 3: Alignment of BC Hydro Electricity Planning and BC Government Objectives

3.3 *Resource Acquisition Initiatives*

Government energy policy creates a target for BC Hydro and other distribution utilities to voluntarily acquire 50% of new supply through clean sources—defined by the policy as technologies that result in a net environmental improvement relative to existing energy production. BC Hydro plans to meet the target through its Power Smart, Resource Smart, Green Energy and Customer-Based Generation (CBG) programs. BC Hydro plans to meet 20% of this target through Green Energy alone.

3.3.1 Power Smart

BC Hydro's target over the next 10 years is to achieve 3,500 GWh[35] per year in energy savings from its Power Smart program. By 2012/13, Power Smart is also expected to reduce system peak demand by about 500 MW and Island peak demand by about 100 MW.

A program example is the Power Smart Traffic Light program, which helps municipalities upgrade incandescent traffic signals to energy efficient light-emitting diode (LED) traffic signals. BC Hydro will purchase Red, Green and Pedestrian "Don't Walk" LED signal lights over a five-year period, recovering half the cost from program participants. Currently, over 40 communities are participating in the program.

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[35] Measured at customers' meters.

3.3.2 Resource Smart

The Resource Smart Program was initiated in 1988 to identify and implement efficiency gains at existing BC Hydro facilities. Resource Smart provides additional electricity to the BC Hydro system by modifying, updating and retrofitting existing generation facilities. An example is the addition of the fourth turbine at Seven Mile Generating Station located on the Pend D'Oreille River near Trail, BC. Unit 4 is currently under construction and will increase generation at the facility by approximately 300 GWh per year. It will have an installed capacity of 210 MW and a dependable capacity of 90 MW. By September 2001, Resource Smart activities had brought approximately 740 GWh/year of restored and new energy into service. BC Hydro plans 1,200 GWh/year of Resource Smart improvements by 2012/13.[36] Vancouver Island Resource Smart improvements of 94 GWh/year are planned over the next decade.[37] These improvements will add energy capability but little or no capacity,

3.3.3 Green Energy

In April 2000, BC Hydro invited IPPs to submit proposals for new Green Energy projects. More than 80 proposals were received, resulting in EPAs for 22 projects. These projects are located throughout BC and have a combined potential to generate 930 GWh per year. They include 20 small hydro facilities, one biomass project and one green landfill gas project. Of these projects, the installed capacity on Vancouver Island is expected to be approximately 25 MW; the expected dependable capacity, 6 to 8 MW.[38] The IPPs are now developing these projects.

In October 2002, BC Hydro invited IPPs to submit further Green Energy qualification statements. 70 proposals were received by the December 2002 deadline and BC Hydro is currently evaluating the projects. Qualification statements of the proponents are being reviewed against the mandatory requirements and project criteria. BC Hydro plans to release the list of qualified and eligible bidders for the tendering stage in March 2003.

3.3.4 Customer-Based Generation

In May 2002, BC Hydro invited commercial and industrial customers to submit qualification statements for customer-based generation (CBG). BC Hydro's target is to bring 800 GWh/year of CBG on line by 2006. BC Hydro received 37 proposals and has issued a call for tenders to the 22 qualified proponents. Short-listed projects include wood waste, natural gas and hydro projects. Selection of proponents for final negotiations is expected to take place in the summer of 2003.

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[36] This amount includes projects currently in progress but not completed, such as Unit 4 at Seven Mile GS.

[37] These are turbine upgrades at the following generating stations: Ash (26 GWh/year), John Hart (36 GWh/year), Ladore (5 GWh/year), Puntledge (18 GWh/year) and Strathcona (9 GWh/year).

[38] Many Green Energy sources have limited ability to provide dependable capacity to meet peak customer demand. For example, run-of-river hydro facilities typically experience low stream flows during cold winter periods, the time that is coincident with peak demand.

Planning studies currently include an estimated contribution of 100 MW of dependable capacity from Green Energy and CBG programs. Of this amount, it is assumed that 25 MW will be located on Vancouver Island.

3.4 *Greenhouse Gas (GHG) Emissions*

On December 17, 2002, Canada ratified the Kyoto Protocol to the United Nations Framework Convention on Climate Change. The Protocol, which still requires ratification by other countries, seeks to reduce overall emissions of greenhouse gases such as CO_2 (carbon dioxide), CH_4 (methane), and N_2O (nitrous oxide) by at least 5% below 1990 levels in the commitment period of 2008 to 2012. For Canada, the reductions required are 6%. BC Hydro actions to manage GHG emissions include:

- ☐ reducing electricity consumption through Power Smart;
- ☐ meeting electricity needs through low GHG-emitting resources such as Resource Smart, Green Energy and CBG; and
- ☐ investing in direct emission reduction in other sectors, such as BC Hydro's purchase of GHG emission reduction (33,400 tonnes over 14 years) from Norseman Engineering Ltd., which collects and refines methane at the Port Mann landfill site and pipes it to a nearby factory, where the methane is used as fuel.

Although the VIGP will use proven technology to ensure that it is one of the cleanest natural gas-fired generation facilities in North America, it will increase BC Hydro's GHG emissions. Therefore in 2000, BC Hydro committed to offset 50% of the net increase in GHG emissions from the ICP and the VIGP through 2010.[39] The VIGP's CO_2 equivalent emissions (CO_2e)[40] are estimated at 750,000 CO_2e tonnes per year, based on an estimated electricity production of 2,100 GWh per year[41] and a GHG intensity of 356 tonnes/GWh.[42] The cost of these offsets through 2010 is included in the portfolio analysis discussed in chapter 5.

3.5 *Electric System Planning Criteria*

BC Hydro is a member of the Western Electricity Coordinating Council (WECC), one of ten regional councils of the North American Electric Reliability Council (NERC). The WECC oversees the operating and planning compliance requirements for maintaining the reliability of the interconnected system of the western United States and Canada (the

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[39] *Greenhouse Gas Report* (BC Hydro: June 2001) at 3 (available at *http://www.bchydro.com/rx_files/environment/environment1898.pdf*).

[40] Unit of measurement indicating the global warming potential of each of the six greenhouse gases identified in the Kyoto Protocol. It is used to evaluate the impacts of releasing (or avoiding the release of) different greenhouse gases.

[41] See section 6.

[42] See section 10.6 of the EAO Application for details.

Western Interconnection). These industry organizations were established to promote the reliable operation of the interconnected bulk electric system by coordinating the planning and operation of generating and interconnected transmission facilities. In fulfilling this function, NERC and WECC develop and promulgate numerous reliability policies, standards, principles and guides.[43]

3.5.1 Generation Reliability Planning Criteria

Under NERC/WECC policy, all generation facilities should be operated to achieve the highest practical degree of service reliability. BC Hydro plans on the basis of both capacity planning criteria and energy planning criteria to ensure that long term electricity supply is adequate to meet probable demand.

Capacity planning criteria ensure that sufficient generation capacity is available to provide a high reliability of serving the annual peak demand, maintain scheduled frequency, and avoid loss of firm load after transmission or generation contingencies. The peak generating capacity of the electric system is designed to meet or exceed the forecast peak demand and to provide a peak reserve margin. The WECC has established a number of generation reserve standards, including:

- a set of mandatory minimum operating reserve criteria; and
- a set of non-mandatory, but recommended, planning reserve criteria.

In terms of generation planning reserve criteria, the WECC recommends that utilities carry sufficient dependable capacity reserves to allow them to withstand temporary outages of individual generating units.[44] BC Hydro, like most other North American utilities, has chosen to adopt the *loss-of-load probability* criterion.[45] This method is a probabilistic assessment of the potential for simultaneous outages of generating units in a shortfall of supply capacity to meet demand in any hour over the year. BC Hydro has applied this criterion by adopting a one-day-in-ten-years allowable risk of load loss.

Current application of this loss-of-load criterion translates into maintaining planning capacity reserves of approximately 14 percent of dependable supply. However, BC Hydro's intertie connections with other electricity systems allow it to reduce its planning reserves somewhat in favour of importing capacity when needed. Based on studies of the combined systems undertaken jointly with other utilities, BC Hydro factors up to 400 MW of market imports into its capacity planning reserves for the integrated system.

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[43] The detailed NERC/WECC requirements are in the report: *Reliability Criteria* (WECC, August 2002) available at *http://www.wecc.biz/op_pppc.html*.

[44] For generators, dependable capacity is the megawatt output that can be relied on with a high degree of confidence to meet system peak demand for electricity. In the BC Hydro system, peak demand can occur between November and March, but more typically in December or January. See section 2.1.

[45] *Generation Planning Criteria*, BC Hydro (May 3, 1984) at p. 7, prepared in response to the BCUC request that BC Hydro "re-examine the use of its critical 44-month periods (1942-46) for planning purposes, [and] examine the feasibility and reliability of using statistical methods to extrapolate a long-term runoff sequence [and] expand the rationale of its planning criteria and assumptions and implications inherent in them."

Energy planning criteria ensure that sufficient generation resources are available to satisfy the system's annual energy requirements. BC Hydro's energy planning criteria are still largely a function of the predominance of hydroelectric resources in its system. For hydroelectric systems, energy capability is limited by water availability.

BC Hydro's energy reliability criterion requires that the expected amount of unserved energy demand in any given year must be less than 0.8% of the total annual energy demand. Based on this criterion, BC Hydro currently schedules new energy resources to ensure that reliance on market purchases or non-firm energy is limited to 2,500 GWh in any one year. To keep the probability of using non-firm resources low enough that energy costs remain economic, the planned non-firm purchases (2,500 GWh per year) would typically be required only in extremely low flow conditions. In average and better flow conditions, additional hydroelectric generation is generally available to reduce imports and displace thermal generation. BC Hydro can also use the flexibility in its reservoir system to minimize required purchases during high-price periods.

The energy generation that a resource can reliably sustain is often referred to as its firm energy capability. BC Hydro generally determines the firm energy capability of its resources as follows:

- ☐ Hydroelectric: BC Hydro examines the energy capability of its hydroelectric resources over a wide range of stream flow conditions. The annual generation that can be sustained in all water conditions within the historical record is considered the firm energy capability of the system.
- ☐ Thermal: The firm energy of thermal resources is determined from their installed capacity, maintenance requirements, unit forced outage rating, and, in the case of gas-fired plants, gas availability.
- ☐ Energy Purchase Agreements: BC Hydro has energy purchase contracts with numerous IPPs and other suppliers. The firm energy capability of such acquisitions may be identified in the contract or may require an assessment of the characteristics of the resource; e.g., for a contract to buy the output of an IPP's small run-of-river hydroelectric installation.

With the development of open access transmission, electric system reliability is less of a concern than it was in the 1970s and 1980s. At that time, if a system were deficient in resources, load curtailments were likely. Now, with open access, energy supplies are generally available but prices may be high and transmission can be constrained.

3.5.2 System Transmission Planning Criteria

The key considerations in transmission planning are maintaining system reliability and quality of power supply. The need for future reinforcements of the bulk transmission system and the nature of these reinforcements are driven by such factors as:

- ☐ power transfer capability requirements (the amount of power that can be transferred over a particular section of a transmission system in a reliable manner);
- ☐ location and size of new generation resources;
- ☐ expected retirement of existing transmission elements;
- ☐ demand for wholesale transmission access; and
- ☐ economic benefits of reducing transmission losses (for both capacity and energy).

The electrical system is planned and designed to meet an appropriate level of system reliability. This includes certain steady state and dynamic performance standards under various single or multiple contingencies (failures), such as the loss of a major system component.

In particular, the transmission system is planned in accordance with the industry-wide NERC/WECC single contingency deterministic criterion for ensuring adequate system reliability (the "N-1 criterion"). This means that the transmission system should be able to withstand a severe short circuit and outage of any single element (such as a transmission line, cable circuit, generator, or transformer) under any system condition. There should be no loss of customer load; furthermore, any resultant variation in voltages or frequency must be within acceptable limits. This reliability standard governs BC Hydro's planning and operations for Vancouver Island.

Several long-term reinforcement scenarios are constructed that meet the single contingency criteria for each year of the plan. The portfolio with the lowest present value of costs over the planning period is usually the preferred option. While a particular scenario may have a higher level of reliability in a particular year because of the addition of a large reinforcement, the reliability of the different lumpy scenarios will likely average out to be similar over time. In the event of a double ("N-2") or greater contingency, the NERC/WECC planning standards permit controlled interruption of firm load, such as by direct or under-frequency load shedding.

The single contingency planning criterion provides good long-term system performance only if the remaining elements have a high level of availability. Therefore BC Hydro derates those supply elements that it considers to be unreliable or have low availability.

3.5.3 Vancouver Island Planning Criteria

The NERC/WECC reliability criteria summarized in the preceding section apply to the entire BC Hydro control area, including Vancouver Island.[46] Specifically, reliable electricity supply to the Island must meet the single contingency planning criterion.

The Vancouver Island system is planned to withstand the worst single contingency: the loss of one of the two 500 kV circuits during system winter peak demand. The largest single element of transmission supply to the Island is one of the two 500 kV AC circuits that supply the Island from the Mainland. Weather events such as cable icing and snow loads, mudslides, and lightning strikes are the main cause of 500 kV outages. For example, in December 2002, both the 500 kV lines were forced out of service:

- The first incident was the loss of the Cheekye-Malaspina line 5L32 due to a mudslide in December 12, 2002. This outage did not result in any load interruptions or power outages to customers. However, this outage placed the Island in a single contingency mode of operation. Repairs of 5L32 took almost six weeks; the line was restored to service on January 21, 2003.

- The second incident was the failure of the parallel circuit 5L30 on December 26, 2002, creating a double contingency and a complete loss of the 500 kV interconnection to the Island, as 5L32 was still undergoing repairs. The loss was caused by heavy ice loading on the conductors in a section of the line, causing the conductors to sag and flash over to trees. 140,000 customers on the Island and the Sunshine Coast lost electricity. Service was restored to residential customers within 36 minutes; industrial customers were notified approximately 3.5 hours later that restoration of service could begin.

Events such as these—all of which are inherently unpredictable—point to the importance of the single contingency criterion.

3.5.4 Economic Advancement of Resources Acquisitions

To optimize the timing of resource acquisitions, BC Hydro assesses the merits of acquiring resources in advance of reserve requirements. Advancing resource acquisitions also advances capital and other fixed cost commitments. However, such expenditures can sometimes be offset by a combination of reduced annual system production costs and increased electricity trade revenues. The net result of these tradeoffs, taking market price risk into consideration, determines the net economic benefit of advancing a resource.

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[46] The only possible exception to the single contingency planning criterion is a radial system, namely an electric system connected to the interconnected transmission system by one transmission path of a single location. Even so, the loss of the radial system must not cause a reliability criteria violation external to the radial system. Vancouver Island is not a radial extension of the overall electric system.

4 The Need for New Resources

This section provides the rationale for the need for new electricity resources to serve Vancouver Island. The section first presents the electric load forecast for Vancouver Island in the context of BC Hydro's system as a whole. It then describes the available resources to meet that forecast demand. The presentation of demand first, followed by a discussion of supply, reflects the usual approach to resource planning even though the main driver for new infrastructure to serve Vancouver Island is a supply issue: the expected retirement of the HVDC transmission system. The forecast increase in the demand for electricity on Vancouver Island contributes to the need for new infrastructure.

4.1 *Electric Load Forecast*

The electric load forecast is the usual starting point for resource planning. This section first provides an overview of economic, population, and electricity consumption trends for context. It then sets out the peak demand forecast for Vancouver Island.

4.1.1 Overview of Economic and Population Trends for BC

BC is expected to be one of the strongest growing provinces over the longer term, with population increasing at a faster rate than the Canadian average. From a population of 4.1 million in 2001, BC's total population is projected to reach 4.3 million by 2005, 4.6 million by 2010, 4.9 million by 2015, and 5.2 million by 2020, corresponding to average annual compound growth rates of 1.08%, 1.25%, 1.29%, and 1.27%.[47] The comparable average compound growth rates projected for Canada are 0.78%, 0.74%, 0.70% and 0.66% respectively.[48] Overall, BC's economy is also expected to benefit from the province's proximity to the fast-growing Pacific Rim region, as Canada's communication and transportation link to the region. Increasing business activities and a larger population base will generate demand for added support services.

Vancouver Island has traditionally been very attractive to retirees from BC and across Canada because of its mild climate. From a total population of 0.70 million in 2001, the Island is projected to have 0.71 million people by 2005, 0.75 million by 2010, 0.80 million by 2015, and 0.84 million by 2020, corresponding to average annual compound growth rates for each 5-year period of 0.46%, 0.83%, 0.97%, and 1.0% respectively.

Projected increases in electricity sales are mainly due to higher distribution electricity sales, with minimal increases to transmission voltage customers. Population growth will produce more requirements for housing and a larger consumer market, resulting in greater residential and commercial electricity demand.

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[47] *BC Population Forecast 02/05* (BC Stats, Ministry of Management Services).

[48] *Market Research Handbook* (Statistics Canada, 2001).

Increased electricity consumption will also come from growing applications of electrotechnologies and from more automation in general. The use of technologies at home and at work to enhance business productivity and competitiveness is expected to continue. An increasing emphasis on preserving the natural environment, along with growing pressures from global competition, are expected to contribute to a trend in BC's economy towards a higher proportion of value-added manufacturing.[49] Value-added products require the substitution and enrichment of raw materials by other inputs, including energy.

Peak demand on BC Hydro's system arises mainly from residential electric heating and higher lighting load due to shorter daylight hours in the winter. About 20% of BC Hydro's residential customers use electricity as their primary space heating fuel. The comparable figure for Island residential customers is about 40%. Residential electric heating is proportionately higher on the Island because natural gas has only been available there since 1992. Electricity remains the preferred fuel for most multi-family residential dwellings, and the trend in major urban centres is towards denser multi-family dwellings due to limited availability of land for residential development.

As a result of these electricity use trends, growth in peak demand is projected to increase at a higher rate than growth in energy usage, because residential load has a lower *load factor* than industrial load. Industrial load factors are high because large industrial customers generally operate steadily all year and therefore have a relatively constant peak demand through the year. Residential load factors are low because peak demand for residential customers is high in the winter months due to electric heating and lighting, but lower during the rest of the year.

4.1.2 Peak Demand Forecast

The peak demand forecast used in the portfolio analysis in chapter 5 assumes that electricity prices will increase at the rate of inflation (i.e., no increase in real terms) beginning in April 2004. In late February 2003, BC Hydro published its Service Plan in which it noted that: "Subject to BCUC approval, rate increases of between 3% to 6.5% per year over the 3-year planning period are estimated to be required for BC Hydro to meet its allowed return on equity."[50] This information was not available in time to be included in the analysis for this application, i.e., the portfolio analysis in chapter 5. When the portfolios have been modelled to reflect sensitivity to possible BC Hydro annual rate increases of 3% and 6.5%, VIEC will provide the results to the Commission.

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[49] For example, employment in BC's manufacturing and resource processing sector over the last decade has increased at the expense of employment in the resource extraction sector: see *Employment by Industry for British Columbia* (BC Stats, Ministry of Management Services: January 2003).

[50] *BC Hydro Service Plan For Fiscal Years 2003/04 to 2005/06* (February 2003) at p. 32.

4.2 *Electricity Supply*

After obtaining the load forecast, the next step is to analyze the available supply of resources to meet that forecast. This section looks at supply from the perspective of capacity only, since capacity is the key issue in this application.

4.2.1 System Supply

Figure 2 compares BC Hydro's supply of dependable generation capacity to the probable peak demand for the BC Hydro system, with and without the estimated reduction in peak demand due to Power Smart. Planning reserve requirements are added to the forecast demand.

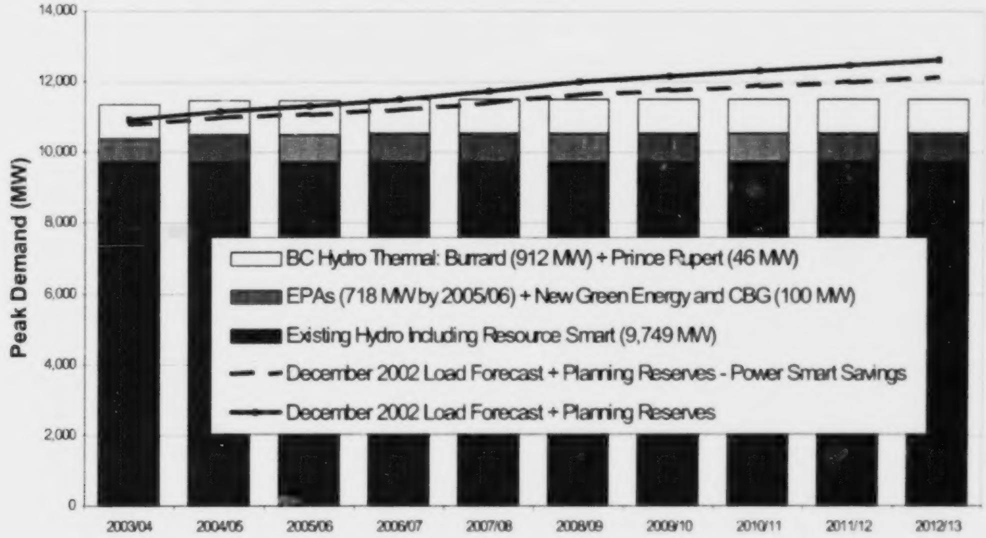

Figure 2: BC Hydro Dependable Capacity/Peak Demand Balance

This figure shows that, without any reductions from Power Smart programs, the BC Hydro system as a whole would be expected to require additional generating capacity in 2006/07. Reductions in peak demand due to Power Smart are expected to defer the need for this new dependable capacity until 2008/09.

4.2.2 Vancouver Island Supply

The Island's electric load is currently served by on-Island resources and by Mainland generation supplied by transmission lines to the Island. The dependable capacity of these resources is described below.

On-Island generation consists largely of a number of hydroelectric generating stations with a total of 450 MW of dependable capacity. BC Hydro also has a long-term electricity purchase agreement with the Island Cogeneration Plant (ICP) in Campbell River. The ICP's dependable capacity is currently 164 MW. The ICP is primarily fired on natural gas, but is designed to have back-up firing using distillate oil. This back-up capability is not yet available at the plant, but is expected by the winter of 2004/05, increasing the ICP's dependable capacity to 220 MW.

BC Hydro is responsible for supplying gas to the ICP. It does so by purchasing transportation from Centra Gas British Columbia Inc., but the Centra pipeline cannot supply all the ICP's fuel requirements without upgrades. The proposed GSX Project would meet the ICP's year round firm gas requirements. Thus the ICP's capability will only be achievable after approval and construction of either the GSX Project or the necessary Centra upgrades.

An allowance has also been included for estimated capacity savings from both the Customer-Based Generation and Green Energy initiatives.

The remaining Vancouver Island electricity firm supply capacity requirements are met by power generated on the Mainland and supplied to the Island by the following three transmission interconnections with the mainland grid:

- **The Cheekye (near Squamish) to Dunsmuir (near Qualicum Bay) 500 kV AC interconnection.** This consists of two contiguous parallel 500 kV circuits: Cheekye to Malaspina (Sechelt Peninsula) overhead lines built in 1983-86, and Malaspina to Dunsmuir submarine cable circuits, installed in 1983-85. The Malaspina to Dunsmuir circuits have overland portions (Malaspina to Cape Cockburn, over Texada Island, and Nile Creek to Dunsmuir) and subsea portions across the Malaspina Strait and Georgia Strait. Each submarine circuit has a continuous rating of 1200 MW. Applying BC Hydro's single contingency reliability standard to the Island means having adequate firm supply capacity to meet the forecast winter peak demand if one of these two 500 kV AC circuits is unavailable. This is the largest or worst single contingency system condition for Vancouver Island. The single contingency firm *power transfer capacity* for these circuits is the two-hour rating of 1300 MW.

- **The Arnott (near Ladner) to Vancouver Island Terminal (VIT—near Duncan) 138 kV AC interconnection.** This interconnection has two 138 kV circuits with submarine cable sections across the southern Georgia Strait and the Trincomali Channel, as well as overhead line portions at each end and on Galiano Island and Saltspring Island. Both circuits were installed in 1956-58 and each has been derated from 128 MW to 100 MW for operating purposes. These cables are now normally operated to serve the south Gulf Island loads (50 MW peak) from the mainland to preserve the cable life. These circuits are considered to be at end-of-life and could fail at any time. Consequently, this interconnection has been assigned zero dependable capacity for planning purposes.

- **The high voltage direct current (HVDC) transmission system between Arnott and VIT.** The HVDC system consists of two sets of cables and terminal converter station equipment that form Pole 1 and Pole 2 of the bi-polar HVDC. The HVDC transmission system has three overhead line sections and two submarine cable sections. The first submarine section is a crossing between the Mainland and Galiano Island across the southern Georgia Strait just north of the 138 kV cables. The second is a shorter crossing through Trincomali Channel between Parker Island and Saltspring Island to just south of the 138 kV cables. The Pole 1 and *Pole 2 terminal converter stations at* Arnott *and* VIT *consist* of two sets of valve groups. Each Pole can operate at half capacity when one valve group or one of the cables is out of service. Pole 1, with a design maximum capacity of 312 MW, was installed in 1969. Pole 2, with a design maximum capacity of 476 MW, was installed in 1976.

These transmission systems are depicted in Figure 3.

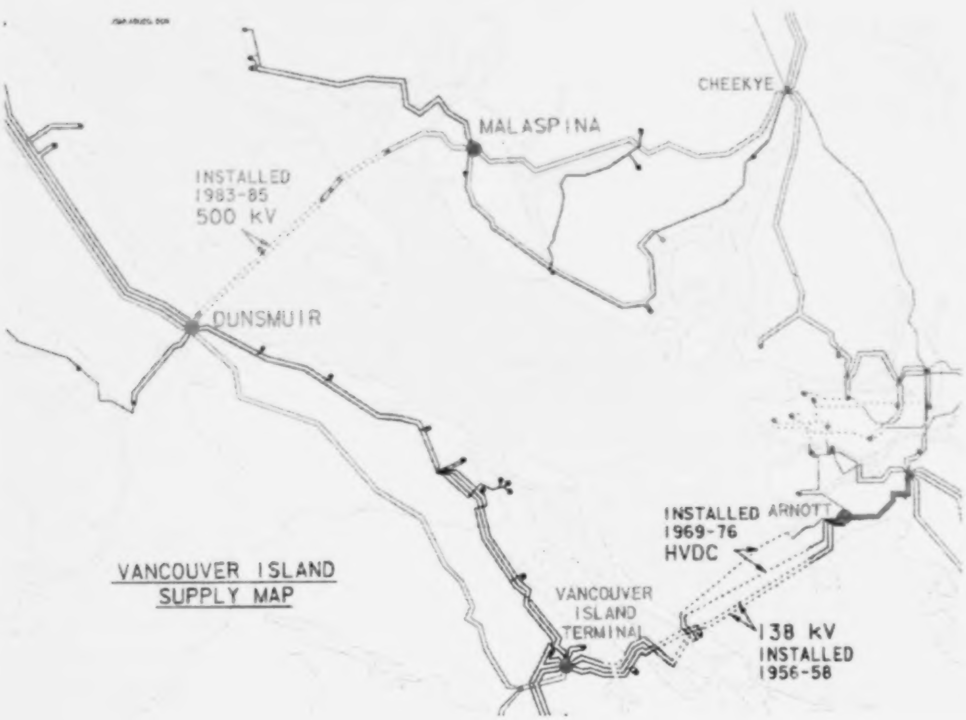
CHEEKYE
MALASPINA
INSTALLED
1983-85
500 kV
DUNSMUIR
INSTALLED
1969-76
HVDC
ARNOTT
VANCOUVER ISLAND
SUPPLY MAP
VANCOUVER
ISLAND
TERMINAL
138 kV
INSTALLED
1956-58

Figure 3: Existing Transmission Connections to Vancouver Island

Vancouver Island supply has been facing increasing electricity supply problems in recent years. Events triggered by planned outages, weather, and equipment failures exposed Vancouver Island to higher risk than would normally be deemed acceptable. In all events, there has been consistent and increasing reliance on the HVDC transmission system. In the period from 1999 to date, there have been numerous incidents, ranging in duration from hours to weeks, where the HVDC system was relied upon for the supply to Vancouver Island for varying capacities up to 600 MW. In the majority of those incidents, the HVDC system withstood the test beyond expectation, as a result of continuing maintenance and refurbishment efforts. However, it is increasingly risky to continue relying on such an aging system without introducing a new supply alternative. Additional refurbishment of the HVDC system is proposed for the next two years, to further mitigate risk pending the in-service date of new additional supply, and to provide more operating flexibility at the early stages of the long-term strategy for Vancouver Island supply.

The exact timing of the retirement of the HVDC system is impossible to predict with certainty. The system's eventual failure is likely to be sudden. Based on professional judgment and consideration of all of the factors involved, the portfolio analysis is based on a capacity of 240 MW for the HVDC transmission system only until 2007. This, along with load growth, drives the need for new infrastructure.

4.2.3 Vancouver Island Dependable Capacity/Peak Demand Balance

Figure 4 demonstrates the application of the single contingency (N-1) reliability criterion to the Island. It shows the balance between N-1 supply capacity and the December 2002 Electric Load Forecast for peak demand, with and without estimated Power Smart peak demand reduction. It shows that even with the achievement of Power Smart targets, dependable resources are only just sufficient to meet Island peak load with reliable and secure supply in accordance with industry and BC Hydro standards. With the expected retirement of the HVDC transmission system by 2007, there is a need for new infrastructure to serve Vancouver Island. Data for Figure 2 is at Appendix C.

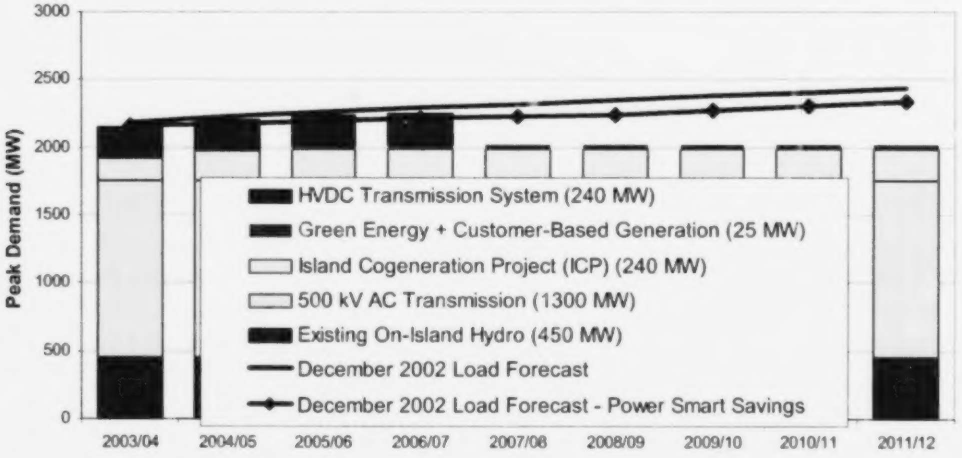

Figure 4: Vancouver Island Dependable Capacity/Peak Demand Balance

5 Resource Portfolios for the Island and BC Hydro System

As noted in chapter 3, BC Hydro determines the most cost-effective means of meeting future system load requirements by building and analyzing alternative 20-year model resource portfolios. The objective of this approach is to identify the optimal schedule of resource additions, i.e., the schedule that minimizes the expected cost of reliably meeting domestic electricity demand over the long-term.

Chapter 4 summarizes when new resources are likely to be needed to reliably meet future BC Hydro system energy and capacity requirements and, coincident with these system planning requirements, describes why new infrastructure will be required to maintain firm supply capability to Vancouver Island. Specifically, a substantial shortfall in Vancouver Island firm supply is expected in 2007/08 due to the HVDC transmission system's expected retirement. BC Hydro's strategy for addressing the shortfall is to develop resource options that meet the Island's reliability requirements while meeting the long-term resource planning objectives for the BC Hydro system as a whole.

The underlying rationale for the VIGP and the GSX Project to which it is integrally linked is that the projects will cost-effectively provide firm electricity supply to Vancouver Island while contributing system energy and capacity need.

5.1 *Portfolio Modelling Overview*

This section summarizes the quantitative and qualitative analyses used to demonstrate the relative economic and strategic merits of the VIGP compared to its alternatives.

5.1.1 Methodology

This subsection summarizes the methodology used to develop and model resource portfolios that represent alternatives for addressing Vancouver Island's electricity requirements. It does so in the context of planning for the future electricity needs of all of BC Hydro's domestic customers.

In general, the development of resource portfolios is based on applying the planning criteria outlined in section 3.4. Reliability planning criteria are used to determine the timing of generation and transmission resources needed to reliably meet the electricity load forecast, net of Power Smart peak demand reductions. As noted in the criteria, resources may be advanced ahead of reliability requirements when economic to do so or to meet other planning objectives.

Alternative portfolios are developed to identify the preferred combination of new generation and transmission investment, taking into consideration existing and committed resources. The economic costs (capital and operating) and in-service lead times of new generation and transmission resources are derived from both internal and third party sources. The costs of producing the energy in the model portfolios are then discounted to today's dollars, and the resulting present values of the costs form the basis for comparing the relative cost-effectiveness of the portfolios.

The portfolio modelling approach used in this application is similar to the approach BC Hydro takes in developing its integrated electricity plans (IEP). In the context of this application, portfolio analysis informs the decision of whether to proceed with the VIGP. That is, alternative resource portfolios are developed in order to isolate, as much as possible, the choice of the VIGP compared to its alternatives.

Consequently, the resource portfolios described in this application reflect the forecast of electricity demand and supply balance, current *economics and effects of policy* decisions, including expenditures made to date on the GSX Project and the VIGP; expected contribution of BC Hydro's resource acquisition strategy (Power Smart, Resource Smart, Customer Based Generation, and Green Energy); and earliest likely in-service dates of the VIGP and other supply-side components.

In addition, the modelling incorporates key linkages between investment decisions. For example, the decision to invest in the VIGP is linked to the decision to invest in the GSX Project. In a portfolio without the VIGP, BC Hydro would not pursue the GSX Project. That, in turn, results in the need for upgrades to the Centra pipeline system in order to supply the ICP's firm gas requirements and support future load growth on Centra's system.

5.1.2 Alternative Strategies

There are three basic resource strategies for meeting Vancouver Island's impending supply shortfall while contributing to system planning requirements:

- ☐ Building new generation on Vancouver Island, which not only serves that region but also supplies dependable capacity and energy to the system as a whole.
- ☐ Addressing Vancouver Island's regional supply constraint with new transmission. This implies that system dependable capacity and energy requirements, including those of Island customers, must be met with generation built on the Mainland.
- ☐ Implementing more aggressive load curtailment to offset the shortfall in firm supply capability to Vancouver Island.

5.1.3 Portfolio Overview

Sections 5.2, 5.3, and 5.4 describe various transmission, generation and demand-side options that were considered for resource portfolio development, along with the rationale for why specific resource options were or were not incorporated into the portfolio models.

Section 5.5 describes three alternative resource portfolios that were developed to represent the range of feasible options and key input assumptions:

- Portfolio 1, referred to as "VIGP Only" because it does not include future on-Island gas generation within the portfolio horizon;
- Portfolio 2, "On-Island CCGTs," so called because it includes further combined-cycle combustion turbines on Vancouver Island after the VIGP; and
- Portfolio 3, called "Mainland Generation" because it does not include the VIGP or future CCGTs on the Island, but relies solely on generation on the Mainland.

Section 5.6 describes the elements common to all options, and section 5.7 presents the results of the portfolio analysis on both an absolute and comparative basis. Sensitivity analyses on the results are set out in section 5.8. Section 5.9 considers factors that are not modelled in the portfolio analysis and section 5.10 summarizes key conclusions.

5.2 *Generation Options*

This section describes the generation options considered for the portfolio analysis and the rationale for the options chosen. Generation resources include hydroelectric, thermal (e.g., natural gas, coal, oil, biomass), market purchases and alternative technologies.[51] BC's new energy policy defines "clean" energy as alternative energy technologies that result in a net environmental improvement relative to existing energy production. Examples may include small hydro, wind, solar, photovoltaic, geothermal, tidal, wave and biomass energy, as well as cogeneration of heat and power, energy from landfill gas and municipal solid waste, fuel cells and efficiency improvements at existing facilities. As discussed in section 3.3, BC Hydro is already pursuing investments in clean energy and expects these resources to be developed on Vancouver Island over time.

For the purposes of this application, generation options considered for the portfolio analysis are divided into four categories: the VIGP, the NorskeCanada Proposal, other gas-fired generation using CCGTs; and non-gas generation resources.

5.2.1 VIGP

The VIGP is based on high efficiency CCGT technology and is included in the portfolio analysis as an economically dispatched 265 MW CCGT plant with a heat rate of 7,308 GJ/GWh and annual energy capability of 2,100 GWh. The VIGP has the following costs (stated in 2002 dollars): (i) $301 million in capital costs (including overhead but not interest during construction); (ii) $6.4 million annual fixed operating cost (excluding gas transportation tolls); and (iii) $4.54/MWh variable cost (excluding gas commodity costs). The VIGP requires the GSX Project to provide firm gas supply. The project's elements are described in detail in chapter 6.

Gas-fired generation, and CCGT technology in particular, has been the resource of choice for most new generation added in North America and internationally in recent years. The US Department of Energy recently estimated that 80% of new generating capacity in the US will be either gas-fired CCGT or combustion turbine (CT) technology.[52] The increase in the use of CCGT technology to provide dependable generating capacity and energy is primarily due to:

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[51] BC energy policy precludes the development of nuclear power in British Columbia.

- ☐ favourable economics, on a multiple account basis, as a result of advancements in gas turbine design;
- ☐ proven performance and high dispatchability relative to other generation resources;
- ☐ low emissions relative to other thermal generation resources;
- ☐ ability to locate gas turbines close to load centres;
- ☐ modular development; and
- ☐ relatively short lead times to meet market demand.

There are also market factors that tend to advantage gas-fired generation over other resources, including the following:

- ☐ There are currently a number of competing equipment vendors.
- ☐ It is generally less expensive to site and build gas pipelines than high voltage transmission lines.
- ☐ There is a competitive, natural gas market in North America.

While CCGTs have relatively low capital costs, they have high variable costs, mostly relating to fuel. While concern over long-term supply of gas has heightened in recent years, current North American forecasts for natural gas continue to show adequate supply and competitive prices over the economic life of a gas turbine.

5.2.2 NorskeCanada Proposal

In December 2002, BC Hydro received an unsolicited proposal from NorskeCanada, BC Hydro's largest customer on the Island. The proposal involves a number of projects that would entail load displacement, power generation, and efficiency improvements. The result may be a reduction in NorskeCanada's peak electricity demand on Vancouver Island by 200 to 250 MW. The projects in the proposal rely principally on gas-fired technologies using existing gas supply. An early assessment indicates that 58 MW have already been accounted for in BC Hydro's planned Power Smart for the Island.

The proposal also states that an additional 50 to 75 MW of demand reductions are possible if additional gas is made available to Vancouver Island via the GSX Project or if distillate is used as a fuel source.

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[52] *Annual Energy Outlook 2003 With Projections to 2025* (US Department of Energy, Energy Information Administration: January 2003) at pp. 67-68.

After netting out projects already accounted for in the peak demand analysis for Vancouver Island, the components of the NorskeCanada proposal that rely on existing gas supply are unlikely to provide sufficient load displacement to make up the supply shortfall created by the expected HVDC retirement. In addition, the technical, regulatory, and financial feasibility of the components of the proposal are unknown and untested. Some components may require significant development work, and if shown to be feasible, may have to be phased in to address technology risks. While NorskeCanada has made conceptual estimates, the energy and capacity that would be delivered by each component is unknown. The proposal's gas requirements and thus its energy capability is uncertain, given constraints on the existing Centra Gas system. Finally, the costs of the proposal to BC Hydro are unknown.

More detailed analysis of this proposal is ongoing. Assuming the proposal is feasible BC Hydro considers NorskeCanada's proposal as a complement to the VIGP rather than a competing project. The proposal does not appear to provide sufficient load displacement to address the predicted capacity shortfall. On the other hand, the VIGP does not preclude development of the NorskeCanada proposal. Both the VIGP and future resources are required to address the HVDC system expected retirement and to meet long-term load growth.

BC Hydro will continue to study the feasibility, cost and timing of the NorskeCanada proposal. However, because of the reliability issues associated with the Island's electricity supply, BC Hydro and VIEC have concluded that it would not be prudent to delay this application any further and consequently has not included the NorskeCanada proposal in the portfolio analysis.

5.2.3 Future CCGTs

This generation resource is assumed to comprise generic 250 MW CCGTs, each having annual energy capability of 1,970 GWh and heat rates of 7,250 GJ/GWh (HHV). Each unit is assumed to have the following costs (stated in 2002 dollars): (i) $285 million in capital costs (including overhead but not interest during construction); (ii) $4.8 million annual fixed operating cost (excluding gas transportation tolls); and (iii) $4.54/MWh variable cost (excluding gas commodity costs).

CCGTs represent an on-Island generation resource that can leverage the gas supply infrastructure (i.e., GSX) required to support the VIGP. Alternatively, they can represent future Mainland generation resources, either following the VIGP or as alternatives to the VIGP. Portfolio 1 follows the VIGP with new transmission and Mainland generation. Portfolio 2 avoids new Mainland-to-Island transmission in the 20-year model by placing future generation on the Island.

5.2.4 Non-Gas Generation Resources

Non-gas generation covers a broad spectrum of both conventional and non-conventional generation resources. These resources are evaluated qualitatively in this application for their reliability and cost.

From a reliability planning perspective, large hydro with storage, and conventional thermal plants (coal, oil, biomass) are more reliable generation resources than small hydro or most other alternative renewable resources, such as wind, which only generate when fuel (e.g., water, wind) is available. Thermal plants tend to be available to operate all the time except for maintenance. By comparison, output from small hydro installations may be limited during cold winter temperatures due to reduced stream flow. Determining the amount of dependable winter capacity available from successful bids under BC Hydro's Green Energy and CBG calls[53] will require verification on a project-by-project basis.

A further consideration is the extent to which there may be sufficient on-Island non-gas generation resources to reliably meet Vancouver Island's electricity requirements, precluding the need for new transmission infrastructure or a gas pipeline from the Mainland. BC Hydro's assessment is that there is no feasible portfolio of on-Island non-gas resources that can be relied upon to provide an adequate supply of dependable capacity in the time required to address the impending capacity shortfall.

That assessment is in part based on the results of Green Energy inventory studies for Vancouver Island, conducted for BC Hydro in 2001.[54] The studies investigated the potential for renewable resources such as small hydro, wood waste, wind, tidal and wave power. They identified significant potential for these resources to contribute to BC's future energy supply. However, such resources are limited in their ability to provide sufficient dependable capacity to make up the expected shortfall in firm capacity to meet the Island's winter peak demand.

Other non-gas resources have also been identified on Vancouver Island, such as biomass, coal, and municipal solid waste. However, the results of BC Hydro's recent CBG call indicated that these projects are not sufficiently advanced to address the expected 2007 supply shortfall. Once the expected capacity shortfall is addressed, smaller projects, such as those described above, will contribute to future electric system resources.

5.2.5 Assessment of Generation Options

Based on the foregoing, BC Hydro does not view either NorskeCanada's proposal or non-gas generation resources located on the Island as being able to reliably meet Vancouver Island's expected capacity shortfall. Consequently, these options have not been considered for further portfolio analysis.

Gas-fired CCGT is widely expected to be the economically favoured resource of choice for meeting future electricity demand across North America.[55] As such, CCGTs represent least-cost generation options that can be sited either on Vancouver Island supplied by the GSX Project (Portfolio 2), or on the Mainland (Portfolios 1 and 3).

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[53] See section 3.3.

[54] *Green Energy Study for British Columbia. Phase 1: Vancouver Island.* (BC Hydro: September, 2001).

[55] See note 52.

In considering the merits of developing a portfolio of non-gas Mainland generation alternatives to the VIGP, a key factor is that the cost to build and operate CCGTs is expected to set the market price of electricity in western North America. Furthermore, IPPs will build, own, and operate future generation in BC (pursuant to government energy policy), and BC Hydro's experience in acquiring private sector resources is that IPPs offer those resources on the basis of BC Hydro's long-term electricity price forecasts. BC Hydro therefore expects future electricity to be priced based on the opportunity value of gas-fired CCGTs.

This market perspective leads to the conclusion that scheduling new Mainland CCGT plants to meet system capacity requirements is also a reasonable proxy for non-gas Mainland generation alternatives to the VIGP. The generic Mainland 250 MW CCGT described in 5.2.4, located at or near Kelly Lake, is assumed to be the specific proxy resource for all competitive gas and non-gas generation types in the portfolio modelling (Portfolios 1 and 3).

5.3 *Transmission Options*

This section describes the Mainland-to-Island transmission options considered for the portfolio analysis. The portfolios that place the next generation resource on the Island defer new transmission but do not replace it. Portfolio 3 requires new transmission immediately because all new generation is on the Mainland.

5.3.1 230 kV AC Cables

This transmission option would replace the existing 138 kV AC interconnection with a two new 230 kV AC circuits, each with 600 MW of firm (dependable) capacity. The life expectancy of this option is 40 years. Lead time for design, regulatory approval and construction is estimated at five years, so the earliest in-service date for this option is 2008. Regulatory issues would include the fact that a new double circuit 230 kV overhead line portion would have considerably more visual impact than the existing 138 kV transmission lines, and that widening of the right-of-way would be required at Sansum Narrows and on Saltspring Island.

The second 230 kV circuit would be installed as required at a later date. The estimated direct capital cost (2002 dollars) is $168 million for the first circuit stage, and $141 million for the second circuit stage.[56] This option does not face the life expectancy risks associated with the HVDC options and has fewer seismic risks (see discussion in following subsection). As work on the option is in a preliminary planning phase, there is uncertainty surrounding the estimates of both cost and timing.

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[56] These are planning feasibility level estimates within a plus/minus 25% uncertainty range.

5.3.2 HVDC Replacement Project

This transmission option involves replacing the converter terminal station equipment at Arnott and VIT and repairing the existing HVDC cables. The first stage, referred to as Pole 3 (replacing Pole 1), would yield dependable capacity of 540 MW. The second stage, referred to as Pole 4 (replacing Pole 2), would provide another 540 MW of dependable capacity. The life expectancy of the new converter station equipment is 30 to 40 years.

A key concern is that the HVDC cables are vulnerable to seismic risk.[57] A further concern is that this option involves repairs and use of the existing HVDC cables, which are 27 to 33 years old. There is uncertainty as to whether they would last for the 30 to 40 year economic life of the new converter stations. The lead time for this project is estimated at three to four years for design and construction. The estimated capital cost (direct costs, 2002 dollars) of Pole 3 is $172 million, and of Pole 4 is $213 million.[58]

5.3.3 500 kV AC Cables

BC Hydro has considered a number of 500 kV options for transmission to the Island:

- a seventh cable with fast switching ability, essentially as a spare single-phase cable for the existing 500 kV system to the Island (comprising six single-phase cables);
- a third 500 kV circuit parallel to the existing 500 kV circuits in the northern corridor; and
- a third 500 kV circuit parallel to the existing HVDC circuits in the southern corridor.

These options were rejected based on their high cost and associated environmental and regulatory approval hurdles. The seventh cable option is also technically inferior to the 230 kV AC option, as it requires complex switching and does not provide the additional reliability benefit afforded by a transmission option on a separate corridor.

5.3.4 Assessment of Transmission Options

BC Hydro has concluded that the only potentially viable transmission planning options are the HVDC Replacement Project and the 230 kV AC Cables. Although planning for these two options is not as well advanced as it is for the VIGP, and although their later in-service dates raise near term reliability concerns, they appear to demonstrate that new transmission from the Mainland to Vancouver Island is a possible alternative. The capital costs of these two transmission alternatives are comparable, but the 230 kV AC option has less risk of seismic damage or aging components. While a more detailed evaluation of the two transmission options is required, at this time the 230 kV AC option is preferred. The portfolio analysis includes the costs and in-service date of the 230 kV AC circuit as representative for the purposes of modelling Portfolios 1 and 3.

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[57] Portions of the HVDC corridor across Georgia Strait have a high likelihood of a seismically-induced shallow flowslide that could cause the cables to fail, because the flowsliding of loose sandy materials during a seismic event would generally be parallel with the cables. A less likely, more deep-seated slide, initiated by static conditions (such as greater deposits of sediment along the shore) or seismically, could take out the cables and cause other shoreline damage.

[58] These are preliminary design level estimates within a plus/minus 15% uncertainty range.

5.4 *Load Curtailment*

Load curtailment can be used to reduce demand for a short period when needed. There are three curtailment options:

- involuntary curtailment: implemented through rolling blackouts by BC Hydro without action by customers;
- voluntary curtailment: implemented in the residential, commercial and industrial sectors at the request of BC Hydro and government agencies; and
- contractual curtailment: usually implemented by industrial curtailment contracts.

BC Hydro uses involuntary and voluntary curtailments only as emergency operational tools. Planning for load curtailment would increase the risk of larger load interruptions on the Island in response to a contingency. Planned load curtailment also tends to restrict economic growth rather than foster it.

BC Hydro currently offers a load curtailment tariff (Rate Schedule 1852) that allows a customer to reduce its billing load through load-shifting activities. In return, BC Hydro can call on the customer to curtail a specified load when needed. The tariff is available to all industrial customers.[59] BC Hydro does not consider the load curtailment provisions in its long-term planning assumptions, since the terms of a Schedule 1852 contract must be renewed annually and the tariff allows the customer, on a limited basis, to reject an offer by BC Hydro to reduce load. The total level of contracted load curtailment under this tariff on Vancouver Island is substantially less than 240 MW and is thus not a feasible option for meeting the expected capacity shortfall on the Island.

5.5 *Portfolio Descriptions and Key Input Assumptions*

Based on the assessment of transmission, generation and demand-side options identified in this application, BC Hydro developed three resource portfolios to be modelled over a 20-year planning horizon. These portfolios are intended to represent the range of feasible least cost transmission and generation options for addressing Vancouver Island's expected capacity shortfall while meeting system energy and capacity needs. The portfolios are described as follows:

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[59] That is, all customers supplied with electricity at 60 kV or higher who are taking service under Rate Schedule 1821 and are party to a Modified Demand Agreement that is in force. The load curtailment tariff is applicable in Rate Zone 1, excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

- Portfolio 1, also referred to as "VIGP Only" and "Reference Case." The VIGP is followed in 2010/11 by a new transmission circuit to the Island and future system generation requirements are met with Mainland 250 MW CCGTs, as a proxy for all competitive generation resources.

- Portfolio 2, referred to as "On-Island CCGTs." The VIGP is followed by an additional on-Island 250 MW CCGT in 2010/11 and another in 2016/17. In this portfolio, no new transmission to the Island is needed within the model's 20-year planning horizon.

- Portfolio 3, also called "Mainland Generation." This portfolio relies on new transmission to the Island, installed at the earliest possible in-service date of 2008/09. System generation requirements are met with Mainland 250 MW CCGTs as proxy resources for both capacity and energy, starting in 2010/11.

Since Portfolio 3 does not have the GSX Project, it includes the estimated cost of the upgrades to the Centra system that would be required to realize the ICP's full 240 MW capacity. Sunk costs for the VIGP and the GSX Project are also included in this portfolio.[60] In Portfolio 3 there is a delay in addressing the Vancouver Island reliability concern. However, the portfolio does not include any costs to mitigate the reliability risk until new transmission comes in service.

5.6 *Common Elements*

The portfolios have a number of common elements, described below. Capital cost figures are stated in 2002 dollars, and do not include allowance for overhead or interest during construction.

5.6.1 Revelstoke and Mica Units 5 and 6

These projects are the additional units allowed for at BC Hydro's Revelstoke and Mica hydroelectric projects. These provide additional least cost dependable capacity, but little new energy capability. Portfolio 3 schedules Revelstoke 5 in 2008 to meet system capacity requirements, earlier than in the other two portfolios.

The two Revelstoke units are 500 MW each and have a capital cost of $102 million each; the two Mica units are 480 MW each and have a capital cost of $151 million and $119 million, respectively. The cost of the first additional Mica unit, Unit 5, includes the cost of required transmission upgrades.

5.6.2 Interior to Lower Mainland 500 kV Transmission

The portfolios include a detailed scheduling of system transmission reinforcements, such as series capacitor station upgrades and voltage support device additions. Aside from the 230 kV AC cables to the Island, the major future transmission reinforcement is a new

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[60] See subsection 1.5.8.

500 kV transmission line from the Interior to the Lower Mainland. It is assumed to be the second 500 kV Nicola-Meridian line, 5L83, with a capital cost of $215 million. In Portfolio 3 (Mainland Generation), it is assumed to have an in-service date of 2012/13 Since the VIGP and future on-Island CCGTs are dependable generation located in or near load centres (Vancouver Island and Lower Mainland), they can defer the need for this transmission addition. The VIGP defers 5L83 by one year; future on-Island CCGTs defer this addition by two years. Thus the in-service dates for 5L83 in Portfolios 1 and 2 are 2013/14 and 2014/15, respectively.

5.6.3 Additional Common Elements

Each portfolio also includes the following additional common elements:

- the energy capability and dependable capacity contributions of current BC Hydro-owned and contracted resources (see Table 2); and
- the energy capability and dependable capacity contributions expected from the current resource acquisition initiatives (see section 3.3).

Table 4 sets out the key generation and transmission components of each of the three portfolios, along with their respective in-service dates. Resources for each of the portfolios, including common elements, are more explicitly defined below. Monetary amounts are quoted in 2002 Canadian dollars.

	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Portfolio 1	GSX	265 MW VIGP				New Transmission to VI ML Generation		Rev 5	Int - LM 500 kV	Mica 5		ML Generation		Rev 6		ML CCGT	Mica 6
Portfolio 2	GSX	265 MW VIGP				VI CCGT		Rev 5		Int. to LM 500kV Mica 5		VI CCGT		Rev 6		ML CCGT	Mica 6
Portfolio 3	Centra Upgrades			New Transmission to VI Rev 5		ML Generation		Int - LM 500 kV	ML Generation	Mica 5		ML Generation		2nd New Transmission to VI . Rev 6		ML CCGT	Mica 6
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22

Portfolio 1 "VIGP Only" - gas supply to ICP and VIGP via GSX followed by 230 kV AC transmission to VI and ML generation

Portfolio 2 On-Island CCGTs - Gas supply via GSX, both VI and ML Generation

Portfolio 3 Mainland Generation - 230 kV AC transmission to Island, ML Generation, gas to ICP via Centra Upgrades

All Portfolios: All include additions for Power Smart, Resource Smart, Customer Based Generation, and Green Energy

Mica 5 = Mica Unit 5 (480 MW, capacity only)
Mica 6 = Mica Unit 6 (480 MW, capacity only)
Rev 5 = Revelstoke Unit 5 (500 MW, capacity only)
Rev 6 = Revelstoke Unit 6 (500 MW, capacity only)
CCGT = 250 MW CCGT (1970 GWh/yr)

- Gas Supply
- VIGP / VI CCGT
- Transmission

- Capacity Only
- ML Generation (with CCGTs used as proxies for future least cost resource additions)
- 2100 GWh "Additional Clean" followed by ML CCGTs as proxies for future least cost resouce additions

ML = Mainland
VI = Vancouver Island

230 kV to VI = 230 kV AC transmission to Island (600 MW per circuit)
Int. to LM 500kV = New Interior-Lower Mainland 500 kV transmission (1500-2000 MW)

Table 4: Resource Portfolios and In-Service Dates of Portfolio Components

5.6.4 Gas Price Forecast

A forecast of gas commodity prices is one of the key inputs in the resource portfolio analysis. Gas price forecasts are used to estimate the fuel cost of existing and planned gas-fired generation and to forecast wholesale electricity prices. BC Hydro develops its reference gas price forecast based on a detailed assessment of market information and data relating to the long run marginal cost of gas. The reference point used is the Sumas Hub, one of the major pipeline hubs of the North American natural gas market, located in Washington State just south of the Canada-US border. In addition to the reference forecast, high and low gas price scenarios are developed by using maximum and minimum gas price forecasts prepared by a number of industry agencies. For the purpose of portfolio analysis, prices beyond the forecast period are assumed to stay constant in real terms.

Gas price uncertainty has a short-term and long-term component. Short-term price volatility can be significant. It is caused by factors such as weather or short-duration constraints on gas pipelines and can result in significant increases in short-term or spot market gas prices. Projects like the VIGP are protected against some of this price volatility because their gas supply is managed by mixes of gas purchase contracts designed to mitigate this risk.

Long-term gas prices are forecast to be relatively stable. This expectation is based on the assumption that supply and demand will adjust in response to price signals, even though gas prices are volatile in the short-term..

BC Hydro's reference forecast translates into a real levelized gas price over the 20-year planning horizon of $C 4.80/GJ, with high and low real levelized gas prices of $C 6.60/GJ and $C 4.10/GJ, respectively.[61]

5.6.5 Electricity Price Forecast

The portfolio analysis estimates the cost of imports and the value of exports, and does so by reference to a forecast of the market price of electricity at the BC-US border. BC Hydro's electricity price forecast is developed in the context of an integrated western North American competitive wholesale electricity market. Capital and other fixed cost commitments associated with advancing supply resources may be partly offset by increased electricity trade revenues.[62] Market prices are also used to value transmission losses.

Forecast electricity prices up to 2012 are based on a forecast of electricity supply and demand, as well as cost drivers that are modelled by a computer simulation of the hourly supply-demand balance for the WECC territory, which includes the western US, BC and Alberta. A key cost driver is the BC Hydro's reference gas price forecast discussed in subsection 5.6.4. Another cost driver is the timing and cost of forecast resource additions. These additions are modelled by CCGTs that are dispatched along with existing resources to derive a detailed marginal electricity price. The cost of the marginal resource at the point where supply and demand are equal determines the market clearing price for that hour. Yearly average prices are obtained by aggregating the computed hourly prices.

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[61] Prices are stated in 2002 dollars, but levelizing commences in 2005/06, the first date by which new resources are added to the system (see Table 4).

[62] See section 3.5.4.

Over the longer term (from 2012 onward), the forecast assumes that electricity prices are based on the estimated unit cost of the most economic resource addition (currently a 500 MW natural gas-fired CCGT), using the gas price forecast described in subsection 5.6.4.

BC Hydro's electricity price forecasts translate into a levelized market electricity price of $C 56/MWh, with high and low levelized prices of $C 71/MWh and $C 51 MWh, respectively.[63]

5.6.6 Vancouver Island Gas Supply

As part of the electricity purchase agreement negotiated with the ICP's owners, BC Hydro is responsible for supplying the natural gas and distillate fuel required for the plant. The existing Centra pipeline to the Island is not capable of supplying the ICP's gas requirements on a firm basis without significant upgrades to the pipeline's delivery capability. Even with dual fuel capability, the ICP's peak output would be curtailed during peak loads, impairing BC Hydro's ability to serve Island electric load and ICP's ability to meet its steam supply obligations to the Elk Falls Mill.

The GSX Project has been proposed as the preferred strategy for supplying gas on a firm basis to the ICP and the VIGP. BC Hydro's intended strategy is to meet the firm gas requirements of both the ICP and the VIGP with firm delivery to Vancouver Island via the GSX pipeline.[64] If the GSX Project is not approved after the relevant federal regulatory hearings, BC Hydro will not continue to pursue the VIGP but will instead pursue new Island transmission options and negotiate with Centra for gas transportation services to the ICP.

The target capital cost of the GSX Project is $322 million. Portfolios 1 and 2 include future GSX expansion costs to accommodate additional Centra load growth. Portfolio 2 also includes future GSX expansion costs to accommodate additional gas-fired generation on the Island beyond the VIGP. The analysis in this application accounts for the fact that significant expenditures have been made to bring the GSX Project to the hearing stage. Approximately $46 million has been spent as of the date of this application and has been included as a cost in all portfolios.

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[63] Prices are stated in 2002 dollars, but levelizing commences in 2005/06, the first date by which new resources are added to the system (see Table 4).

[64] This assumes that 50% of the GSX Project's annual revenue requirement is attributable to the VIGP (the other 50% being attributable to the ICP).

If the VIGP and the GSX Project do not proceed, the Centra system would need to be expanded. The facilities required and costs to expand the Centra system to supply the ICP, plus Centra's core load growth, were evaluated by Singleton Associates Engineering Ltd. ("Singleton"). Singleton has estimated that Centra would have to incur $218 million in capital expenditures for expansion facilities over the next 20 years if the GSX Project does not proceed. The facilities required include a number of compressors and the looping of several segments of the pipeline, primarily on the Mainland. Also included in the analysis are the estimated quantities and costs of compressor fuel required for each of the pipeline alternatives.

5.7 *Portfolio Analysis and Discussion of Results*

This section presents and discusses the relative present value of the costs of the three resource portfolios described above, and examines the question of whether the VIGP is the most cost-effective means of meeting Island electric reliability requirements.

5.7.1 Portfolio Analysis

Each portfolio was analyzed using BC Hydro's system simulation model to determine the expected annual generation from each resource available in the portfolio. The model economically dispatches existing and new resources within the portfolio to meet domestic load requirements first and then trade, as outlined in subsection 2.1.5. The model dispatches available resources for each year of a 20-year study. It selects resources to meet demand based on their variable operating cost or *dispatchability*. This means that resources with zero dispatch cost are used first. This includes IPP contracts. Then the model uses BC Hydro's run-of-river hydro and smaller hydro projects that do not have significant storage capability. Their variable cost is the water rentals.

For larger hydro projects with reservoir storage, the model also takes into account the value of water stored in the reservoir in its dispatch decisions. The value of water in a reservoir is an estimate of the expected reduction in costs made possible by the future release of this water taking into consideration factors such as current reservoir elevations, available reservoir storage and the range of potential future inflows. As such, it represents the opportunity cost of releasing water in the current time period rather than storing it for future use. In each month, the model compares the value of stored water to the variable cost (mostly fuel) of dispatchable thermal resources (such as Burrard GS, Prince Rupert GS, and the VIGP), and the cost of imports and the value of exports in that month. In that way, it determines how much hydroelectric energy to use.

The fuel costs for Burrard GS, Prince Rupert GS, and the VIGP, are based on the forecast market price of gas at Sumas Hub, discussed in subsection 5.6.4. The value of imports and exports is based on the forecast of wholesale electricity market prices at the BC/US border, discussed in subsection 5.6.5. Depending on prices, it may be more economic to import than to dispatch higher cost resources. The model conducts its detailed dispatch for each future year. To assess the performance of the portfolios under a range of future stream flow conditions, the dispatch is repeated several times, utilizing the historical streamflow sequence from 1940 through 2000. The results from each sequence are averaged to arrive at an expected dispatch of each resource and expected imports and exports.

To compute the cost of energy for each portfolio, the expected dispatch in GWh for each thermal plant is multiplied by its corresponding fuel prices and the import and export quantities (GWh) are multiplied by their respective prices. These costs are combined into annual totals for each item (Net Generation Cost). These portfolios also include an appropriate transmission loss differential for CCGT Mainland generation relative to a Vancouver Island site, with transmission losses valued at the market price for electricity.

All costs are analyzed and presented in Canadian 2002 dollars. The present value of future costs net of trade revenues (NPV Cost) was calculated at an 8% real discount rate. Table 5 summarizes the results, using Portfolio 1 as the Reference Case.

	Portfolio 1 **VIGP Only**	**Portfolio 2** **On-Island CCGTs**	**Portfolio 3** **Mainland Generation**	**Portfolio 2** **minus** **Portfolio 1**	**Portfolio 3** **minus** **Portfolio 1**
Net Generation Cost	8,762	8,762	8,762	0	0
Vancouver Island Gas transportation	455	480	347	25	-108
Transmission Cost Including Losses	460	283	577	-177	118
Total NPV Cost	9,677	9,525	9,687	-152	10

Table 5: Comparison of the NPV Cost of Alternative Resource Portfolios ($ Millions)

5.7.2 Discussion of Results

Portfolio 1, in which the GSX Project and the VIGP are followed by new transmission to the Island, is used as the Reference Portfolio. The analysis indicates that the NPV Cost difference between Portfolios 1 and 3 is $10 million. The difference in the NPV Cost of gas transportation to Vancouver Island is almost the same as the NPV Cost of electrical transmission. However, Portfolio 3 does not include the cost of mitigating the risk of a shortfall in Vancouver Island firm supply prior to the in-service date of new transmission. Any such costs would further increase the cost of Portfolio 3 relative to Portfolio 1.

The analysis indicates that Portfolio 2—On-Island Generation—is the least cost portfolio. The NPV Cost of this Portfolio is $152 million less than Portfolio 1. This difference is largely due to the small incremental cost in Island gas transportation to accommodate future Island CCGTs. This is the cost of additional compression on the GSX pipeline, with an NPV Cost of only $24 million. This relatively small additional gas transportation cost avoids $177 million in NPV Cost of transmission.

The GSX Project enables an economically attractive option because it can support additional Island gas-fired generation. However, because Portfolio 1 is at least as economic as Portfolio 3, investment in the GSX Project and the VIGP does not make investment in future gas-fired generation on Vancouver Island inevitable.

Furthermore, the GSX/VIGP combination addresses the Island's immediate reliability concern. With that shortfall addressed, BC Hydro anticipates that other on-Island supply-side and demand-side options will emerge over time. Addressing the immediate concern with GSX/VIGP allows time for Island customers, particularly industrial customers, to pursue Power Smart or customer-based generation opportunities and for the private sector to pursue other options. These options are expected to be in small increments potentially suited to meeting the annual demand growth on the Island.

5.8 *Sensitivity and Risk Analysis*

This section addresses portfolio risk and sensitivity of the input assumptions. Sensitivity analysis was undertaken to assess the robustness of the portfolio results against gas price risk, discount rate, and cost/schedule/timing/ certainty.

5.8.1 Gas Price Risk

The factor most affecting the cost of energy for the VIGP is gas price. Table 6 illustrates this, again using an 8% discount rate.

	Portfolio 1 VIGP Only	**Portfolio 2 Minus Portfolio 1**	**Portfolio 3 Minus Portfolio 1**
High Gas price Scenario	11,528	-175	36
Sumas Hub Reference Price	9,677	-152	10
Low Gas Price Scenario	9,417	-149	-9

Table 6: Portfolio Sensitivity to Gas Prices ($ Millions)

Under the High Gas Price scenario, Portfolio 3, in which new Mainland generation comes on line in 2010, is more expensive relative to Portfolio 1 than it is under the Sumas Hub price. Portfolio 3 has higher cost of transmission losses. Portfolio 2 remains the least cost portfolio in the High Gas Price scenario. While this may seem counter-intuitive, it is consistent with the notion that the most efficient gas-fired resources become more economic relative to less efficient gas-fired resources. In an electricity market for which electricity prices remain largely driven by gas prices, high gas prices provide an economic incentive to invest in more efficient generation technology. Similarly, the VIGP is more efficient than existing gas-fired resources. Thus it will economically displace existing higher cost resources.

In the Low Gas Price scenario, Portfolio 3 is slightly lower cost than Portfolio 1. This is because the advantage of having a CCGT (the VIGP) available earlier is diminished and the cost of transmission losses are lower. As already noted, though, there is no mitigation cost included to address the supply shortfall on Vancouver Island prior to the new transmission being in-service.

Although the VIGP is expected to operate at a very high load factor, it is a dispatchable plant. That feature helps to mitigate gas price risk. In periods of short-term volatility when there is less correlation between electricity and gas prices (and the market price of electricity is lower than the VIGP's dispatch cost) and it is not needed to meet system or Vancouver Island peak electricity demands, market purchases could displace the use of the VIGP. In effect, its off-peak dispatch cost would not go higher than the market price of electricity. This flexibility is a valuable attribute of the VIGP.

5.8.2 Discount Rate Sensitivity

Discount Rate sensitivity is provided in Table 4. The relative economics of the four portfolios does not change over a range of 6% to 10% real discount rate. This lack of sensitivity to discount rate is because the majority of new generation supply in the portfolios has a relatively low capital cost.

	Portfolio 1: VIGP Only	**Portfolio 2 Minus Portfolio 1**	**Portfolio 3 Minus Portfolio 1**
6% real discount rate	14,387	-206	14
8% real discount rate	9,677	-152	10
10% real discount rate	7,026	-120	4

Table 7: Portfolio Sensitivity to Discount Rates ($ Millions)

5.8.3 Cost, Schedule, and Timing Certainty

The VIGP benefits from a higher degree of construction cost and schedule certainty relative to its alternatives, due to the detailed engineering and siting work and the advanced stage of regulatory review and approvals, particularly those related to the

GSX Project. Also, the VIGP has an expected in-service date of 2006, one year earlier than the expected retirement of the HVDC. This schedule would enhance reliability of electricity supply on Vancouver Island. Figure 5 shows the role that the VIGP plays in addressing the Vancouver Island capacity/demand imbalance over the next decade.

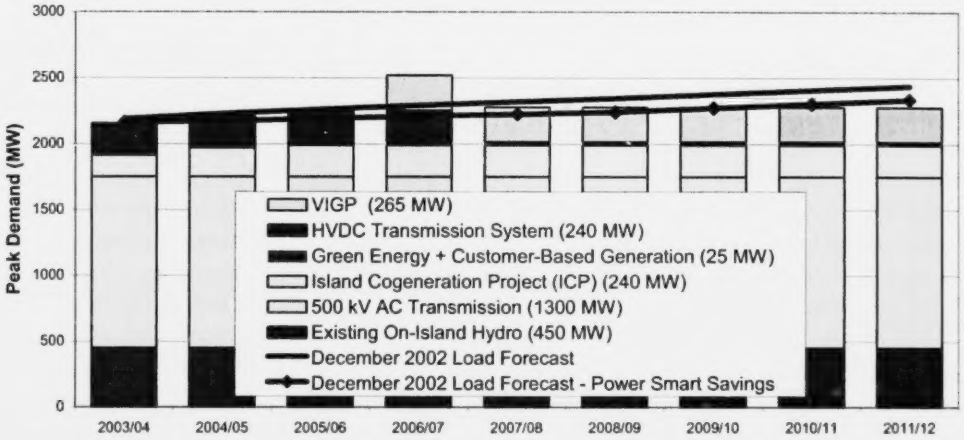

Figure 5: Vancouver Island Dependable Capacity/Peak Demand Balance with VIGP

5.9 *Other Planning Considerations*

This section qualitatively considers additional issues such as benefits of energy supply diversification to Vancouver Island and future planning flexibility. While no quantitative assessments have been undertaken of benefits of the energy supply diversification offered by the VIGP, the project has the potential of improving security of electricity supply to Vancouver Island through diversification of generation location as well as energy transmission (electricity) and transportation (gas). The VIGP also provides a hedge against the risk of a low water year on Vancouver Island over the short term.

In addition to providing a valuable option for further Vancouver Island CCGT generation, the VIGP will facilitate development of other resources. Addressing the impending capacity shortfall on Vancouver Island now will also give BC Hydro time to investigate and respond to proposals for smaller increments of new generation and demand-side initiatives, while continuing to consider new transmission options. Ultimately, this will increase BC Hydro's resource planning flexibility in responding to future Island load growth and increase reliability of supply.

On-Island generation additions also defer the need for Interior-to-Lower Mainland bulk transmission additions, which is beneficial given that this 500 kV transmission addition will require significant lead time (up to nine years). This lead time already makes Portfolio 3 resource scheduling challenging.

5.10 *Portfolio Analysis Summary*

Chapter 4 provides evidence that growing demand for electricity on Vancouver Island, coupled with expected retirement of existing transmission capacity, requires additional resources to ensure reliable electricity service to Vancouver Island customers. The BC Hydro system as a whole is also approaching supply/demand shortages with respect to dependable capacity. The key issue for Vancouver Island is that due to the HVDC transmission system's expected retirement, there is a substantial impending shortfall in Island firm supply, making investment in supply infrastructure a high priority.

New generation on Vancouver Island would not only serve that region but would also supply dependable capacity and energy to the system as a whole. Conversely, addressing the Island's regional supply constraint with new transmission implies that system dependable capacity and energy requirements, including those of Island customers, must be met with generation built on the Mainland. Therefore, alternative portfolios were analyzed in the context of long-term resource planning for the whole BC Hydro system.

Under the schedule proposed in this application, the VIGP (Portfolios 1 and 2) would be ready one year before the HVDC system's expected retirement. This schedule would enhance reliability of electricity supply on Vancouver Island, because the HVDC system might reach its expected retirement sooner than 2007. Furthermore, the option of further CCGT development on Vancouver Island by leveraging the gas supply infrastructure provided by the GSX Project (Portfolio 2), represents significant additional cost-effectiveness potential. A resource portfolio with the VIGP is robust when tested against a range of gas prices and discount rates.

The VIGP has greater certainty of capital costs and schedule and offers additional system planning benefits in terms of energy diversification, planning flexibility and deferred Interior-to-Lower Mainland transmission infrastructure.

Nevertheless, a resource plan based on building new transmission to the Island instead of the VIGP (Portfolio 3) may also be an option and appears to be roughly equal in cost to the resource plan that builds new transmission to Vancouver Island after the VIGP (Portfolio 1). However, this strategy may not be feasible, and is may incur additional mitigation costs because the earliest transmission in-service date appears to be beyond the expected HVDC retirement date.

6 Project Description

6.1 *Overview*

The VIGP design incorporates a GE 7FA natural gas-fired, combined-cycle power plant, a connection and upgrade to the existing transmission grid, and a short feeder pipeline to supply natural gas to the plant; a water supply line from the existing Harmac reservoir; a wastewater line to the existing Harmac treatment system; an upgrade of the transmission circuits that provide electricity to industrial users in the Duke Point area; and temporary works needed during construction and start-up. The project, at an expected total cost of $340 million,[65] will provide dependable capacity of 265 MW over its expected 25-year life and have a firm energy capability of 2,100 GWh/year.

The combined-cycle system proposed for the plant is a combustion turbine designed to produce 170 MW of electricity, a heat recovery steam generator (HRSG) to generate steam from the hot turbine exhaust gases, and a steam turbine cycle that will produce 95 to 125 MW of electricity, depending on inlet steam flow. In other words, the system will produce electricity at the rate of 265 to 295 MW. Power generated by the plant will be supplied to the BC Hydro grid at Duke Point, near Nanaimo.

VIEC proposes to locate the plant at a site acquired by BC Hydro from Pope & Talbot Ltd. at its Harmac Pulp Operations site in Duke Point. See Figure 6. The site is already cleared from past development, is zoned for industrial use and compatible with neighbouring industries, and lies far from residential development. The process by which this site was selected from among the possible candidates is discussed in sections 6.3 to 6.5.3.

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[65] Expressed in 2002 dollars and including contingencies, overhead and IDC. See Table 11 of this application.

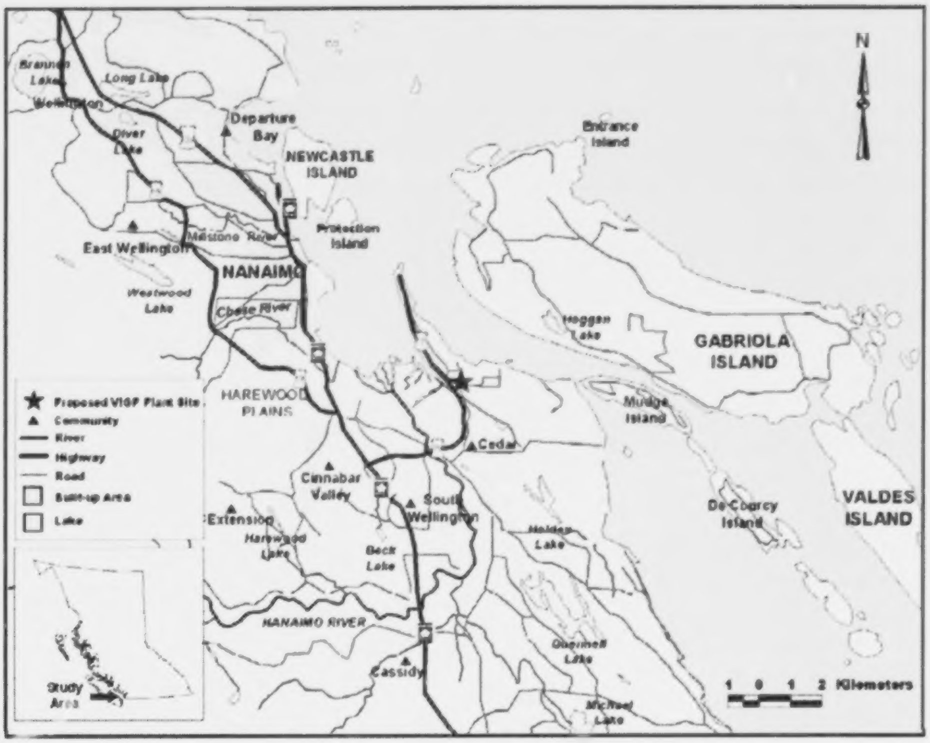
N
Brannen Lake
Long Lake
Wellington
Diver Lake
Departure Bay
NEWCASTLE ISLAND
Entrance Island
East Wellington
Millstone River
Protection Island
NANAIMO
Westwood Lake
Chase River
Hoggan Lake
GABRIOLA ISLAND
HAREWOOD PLAINS
Mudge Island
Proposed VIGP Plant Site
Community
River
Highway
Road
Built-up Area
Lake
Cedar
Cinnabar Valley
South Wellington
Extension
Harewood Lake
Beck Lake
Holden Lake
DeCourcy Island
VALDES ISLAND
NANAIMO RIVER
Quennell Lake
Cassidy
Michael Lake
1 0 1 2 Kilometers
Study Area

Figure 6: Map of Proposed Location for VIGP Plant Site

6.2 *Cogeneration CCGTs and Stand-Alone CCGTs*

For the purposes of generating electricity, the most efficient use of the energy latent in natural gas is a cogeneration plant that combines combustion and steam cycle generation with a host for the thermal energy that would otherwise be wasted. The proposed VIGP plant, though, is a stand-alone, rather than a cogeneration, CCGT. The main reason is the lack of a suitable steam host. This section discusses the relative merits of cogeneration and non-cogeneration stand-alone CCGTs and explains why a stand-alone CCGT was chosen for the VIGP.

6.2.1 Cogeneration Overview

Cogeneration is the generation of electricity and the joint use of thermal energy created from that generation for process steam or heating loads. Cogeneration is widely applied in Canada in the industrial sector, with the top three sectors being pulp and paper, chemical products, and refined petroleum products.

Combined cycle gas-fired generation is a specific use of the exhaust heat from a natural gas-fired turbine generator to make steam that is used in a steam turbine to drive a second cycle of electricity generation. This technology can be applied in a CCGT cogeneration configuration to provide some of the steam to an industrial process instead of assigning it entirely to the second cycle of the generation of electricity. This can increase the overall efficient use of the energy in the gas at the cost of some electricity generation, as long as there is an efficient use of the steam that gets diverted from the generation of electricity.

Cogeneration CCGT technology is used for approximately 2,320 MW of electrical generating capacity in Canada.[66] This amounts to 31.6% of total installed cogeneration electrical generating capacity (CCGT and non-CCGT combined) of 7,349 MW. Total installed cogeneration CCGT capacity is highest in Ontario (1,060 MW), followed by Alberta (800 MW), BC (240 MW—the ICP) and Quebec (215 MW). These systems are all associated with industrial hosts having a large demand for process steam or heat.

6.2.2 CCGT Overview

Typical electricity generation efficiency for large CCGT systems, based on manufacturers' claims for systems designed for 60 Hz power, are summarized in Table 8.[67]

Manufacturer	Gas Turbine Output (MW)	Steam Turbine Output (MW)	Total Output (MW)	Net Thermal Efficiency[68] (%)
Alstom Power	176	84	260	56.6
GE Power Systems 7FA	170	95	265	56.0
GE Power Systems 7FB	181	99	280	57.3
Siemens Westinghouse	2 x 182	197	561	55.8
	250	115	365	58.0
Mitsubishi Heavy Industries	178	103	281	56.7
	247	124	371	58.0

Table 8: Net Thermal Efficiency of Large CCGT Systems (Various Suppliers)

The proposed VIGP plant is designed to have a net thermal efficiency of 54.8%[69] for the specific VIGP site and a net plant heat rate of 6,577 kJ/kWh. The plant efficiency is expected to be fairly steady throughout the year, at approximately 1% less than the value published by the manufacturer. This reflects what is likely to be achievable for the specific site in contrast to design specifications and assumptions, but is nevertheless near the upper limit of what is achievable with commercially proven gas-fired FA technology CCGT power plants.

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[66] C. Strickland and J. Nyboer, "A Review of Existing Cogeneration Facilities in Canada," Canadian Industrial Energy End-Use Data and Analysis Center (CIEEDAC), Simon Fraser University (April 2002).

[67] From M. Greth and M. Susta, "Efficiency Improvement Possibilities in CCGT Power Plant Technology, Power-Gen Asia, Malaysia (September 2001).

[68] Based on the lower heating value (LHV) of the fuel and 60 Hz electrical output.

[69] Net electricity delivered to grid compared to LHV of the natural gas used. (See note 68.)

There are 508 GE F machines in operation with 7.1 million hours of commercial service. A new GE 7FB turbine is scheduled to begin commercial service in 2003. It will use more advanced design features that have evolved from experience gained with earlier F class turbines and research conducted for the H class gas turbines being developed by GE. The main improvements are higher firing temperature (1,371 °C), a higher pressure ratio, and improved metallurgy and blade cooling.[70]

The most efficient CCGT technology nearing commercial operation is GE's H system, which GE claims has a net plant efficiency of up to 60% in a CCGT configuration.[71] This has been accomplished by closely integrating the gas turbine and the steam cycle and applying significant advancements in compressor and gas turbine design. The closer integration of the gas and steam turbine cycles to achieve higher plant efficiency precludes the use of GE's H system in a CCGT cogeneration configuration. The first installation of a CCGT based on the H system is at the 480 MW Baglan Bay Power Station in Wales. It started up in 2002. The second and third installations are scheduled at Sithe Energy's 800 MW Heritage Station in New York in 2004 and Tokyo Electric Power's 1,520 MW Futtsu Thermal Power Station in 2008-2010.

The net power outputs, net thermal efficiencies, and heat rates of GE CCGT systems are summarized in Appendix E. The thermal efficiency of these systems and the GE 7FA system proposed for the VIGP are graphed in Figure 7. The graph demonstrates that the VIGP plant's design efficiency is consistent with that of typical F class CCGT systems of similar size.[72]

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[70] International Power Generation, "It Takes Two" (October 2002).

[71] R.K. Matta, G.D. Mercer and R.S. Tuthill, "Power Systems for the 21st Century – 'H' Gas Turbine Combined-Cycles," GER 3935B, GE Power Systems, Schenectady, NY (October 2000).

[72] See Appendix E for data source.

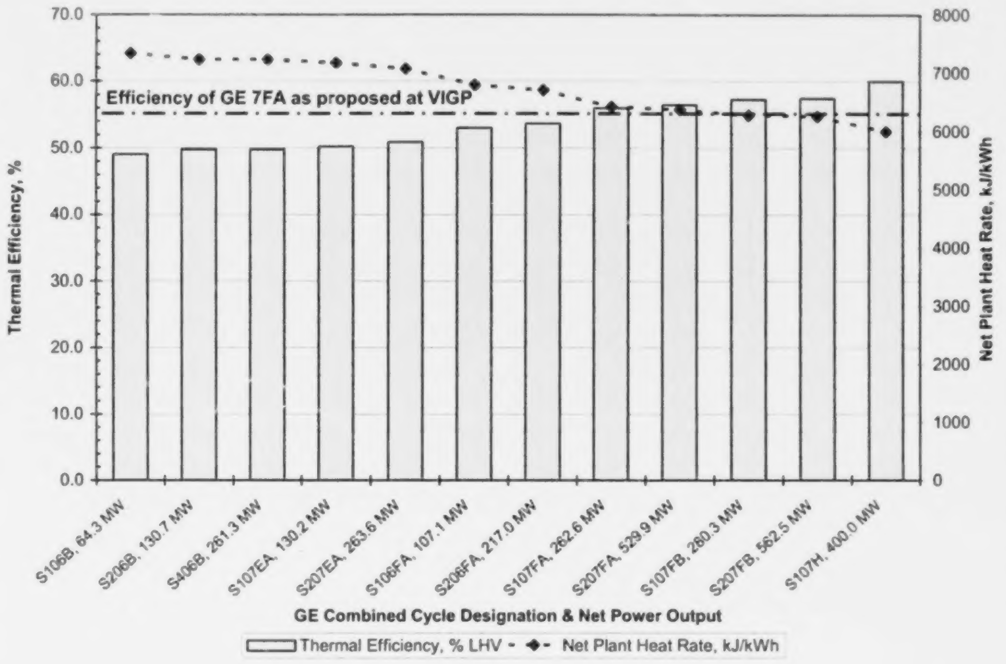

Figure 7: Net Thermal Efficiency and Plant Heat Rate for GE CCGT Power Plants

6.2.3 Design and Operational Issues

Where a thermal host has a compatible demand for heat or steam, the overall thermal efficiency of a cogeneration CCGT power plant will be higher than that for a stand-alone CCGT plant. However, this higher thermal efficiency is associated with a lower efficiency of electricity production and a reduction in plant electrical output capacity. It also gives rise to a number of design and operational issues. Some of the more important issues that need to be considered when developing a cogeneration rather than a stand-alone CCGT power plant are:

- An independent cogeneration CCGT plant would need to be designed so it could operate independently of the thermal host, which shuts down temporarily for maintenance and repair or could shutdown permanently. Hence, the power plant would need sufficient condenser and cooling tower capacity, such as at VIGP, to operate without an external heat load. This design redundancy would increase the plant cost from what would otherwise be required for a cogeneration plant, and would need to be included in the cost of the thermal energy delivered to the host.

- The thermal host would need to maintain backup thermal energy generation equipment to provide thermal energy if the CCGT plant were to shut down, or if the thermal energy demand were larger than what could be delivered by the CCGT plant. This would reduce the cost saving realizable by the thermal host, since some of the costs for the equipment, space, and operation of the equipment would continue after the CCGT would come into service.

- ☐ The operation of the CCGT and the thermal host would be highly interconnected, increasing operational and control complexities and requiring strategies to be developed and implemented to handle transient events, shut-down/startup and normal operational activities at both facilities. Costs could increase if the operation of one facility were to adversely affect the performance or product quality of the other.

- ☐ The host's load profile (magnitude, quality, and variability by hour, day and month) needs to be matched to the CCGT plant's capability, because the thermal load affects the electricity output that can be achieved. There are limits to the combination of electrical and thermal energy outputs that can be delivered reliably: a high level of flexibility leads to increased plant cost and operational complexity. As thermal energy delivery to the host increases, power generation capability decreases.

- ☐ A cogeneration CCGT plant may not have the optimal fit to the host's needs in terms of the quality and quantity of thermal energy. Existing pulp and paper mills, such as Harmac and Crofton, already use conventional cogeneration systems. These systems may already be providing a good fit to the current electrical and thermal energy needs. In such cases, as illustrated by the ICP (see below), the thermal load that could be provided by an external power plant such as the proposed VIGP plant are likely to be comparatively small and result in only a modest increase in total energy efficiency.

As discussed in subsection 1.5.4, VIEC had discussions with potential steam hosts at Crofton and Duke Point, but found that there were no opportunities at those locations in which a thermal host could suitably enable the design and operation of a commercially viable cogeneration plant. VIEC thus decided to proceed with a stand-alone CCGT for the VIGP power plant.

6.2.4 Comparison of Cogeneration and Stand-Alone CCGT Efficiencies

The ICP is an example of a natural gas-fired cogeneration CCGT power plant with an industrial host.[73] Steam is provided from the ICP to the adjacent mill to provide steam that was previously provided by obsolete oil/gas-fired boilers. The plant's total thermal efficiency (net electricity plus 100% thermal energy exported to the mill) is estimated to be 62% in summer and 71% in winter. These estimates likely overstate the potential thermal efficiency (as opposed to the electrical generation efficiency, as they rely on the assumption that all the thermal energy in the steam exported to the Elk Falls pulp and paper mill is recovered and used. In practice, this would not likely be achieved. In summary, to properly compare the VIGP in stand-alone and cogeneration configurations, one needs to compare the thermal efficiency of these two designs for the same electrical and thermal energy output. This is done in Appendix F.

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[73] Island Cogeneration Project Inc., "Application for a Project Approval Certificate: Island Cogeneration Project" (submitted to the Environmental Assessment Office in September 1997).

6.3 *Site Selection Considerations and Screening Process*

Alternative areas and sites on Vancouver Island were identified and evaluated before deciding on the project site proposed for the VIGP. This site selection process consisted of three phases in an overall framework designed to systematically and objectively consider land use and regional planning, engineering, environmental and socio-economic/cultural-heritage factors. The site selection process tried to find the project site that met engineering and business requirements and offered socio-economic benefits to the community, while minimizing or avoiding adverse impacts to the environment, public health and cultural-heritage values.

The site selection process started with a high-level regional overview to identify potentially suitable areas where the project could be located close to essential infrastructure. This screening level search was then progressively narrowed to first develop a short-list of candidate sites, then to rank their suitability using more detailed criteria and site information and, finally, to decide on the most suitable site for the VIGP. Information used for this process came from municipal and regional planners, public databases, existing studies, and site-specific investigations.

The site selection process considered candidate sites within a large area bounded by the east coast of Vancouver Island from near the northern limits of the Nanaimo Regional District, inland from Qualicum Bay, and 100 km south to near Somenos in the District of North Cowichan. See Figure 8. All areas in this region having suitable zoning or that were recommended by municipal or regional government planning staff were considered at some level. The site selection process narrowed the search from 17 sites to seven sites in five areas, then ultimately to the Harmac site.

6.4 *Methodology*

The site selection process consisted of three phases, progressively refining the alternative locations for the VIGP:

- Phase 1: regional preliminary screening to identify and screen potential sites and develop a long-list of potentially suitable candidates for further analysis in Phase 2;
- Phase 2: evaluation and ranking of the long-listed alternative sites to identify the best candidates for final site selection in Phase 3; and
- Phase 3: further site-specific analysis and discussions with the site owner for the best ranked sites to select a preferred project site.

The logic flow for the steps in the site selection process is illustrated in Figure 9.

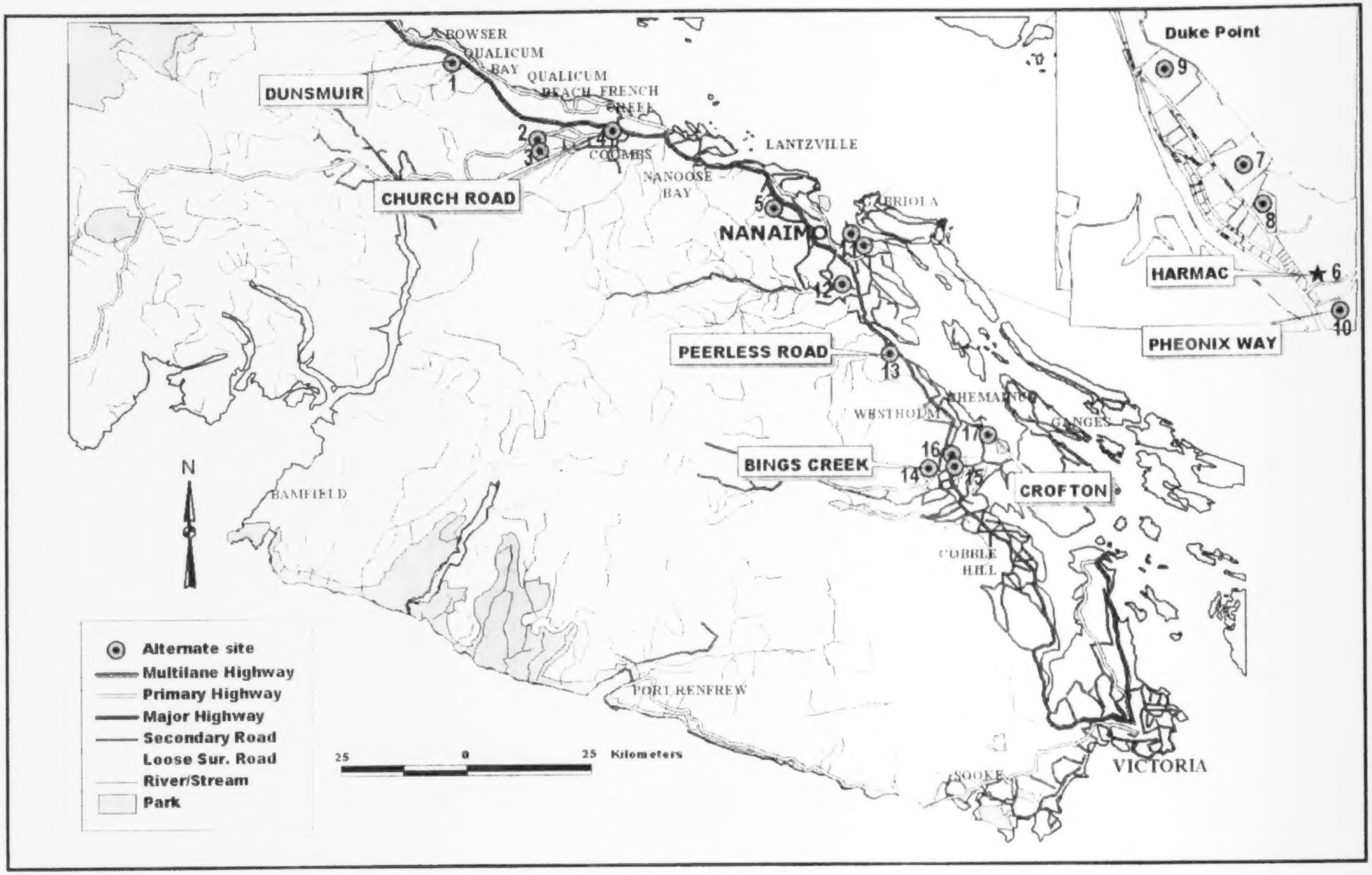
Duke Point
9
7
8
HARMAC
6
10
PHEONIX WAY
BOWSER
QUALICUM BAY
QUALICUM BEACH
FRENCH CREEK
DUNSMUIR
1
2
3
4
COOMBS
CHURCH ROAD
LANTZVILLE
NANOOSE BAY
5
NANAIMO
11
GABRIOLA
12
PEERLESS ROAD
13
CHEMAINUS
WESTHOLME
GANGES
17
16
14
15
BINGS CREEK
CROFTON
COBBLE HILL
BAMFIELD
PORT RENFREW
SOOKE
VICTORIA
N
Alternate site
Multilane Highway
Primary Highway
Major Highway
Secondary Road
Loose Sur. Road
River/Stream
Park
25
0
25 Kilometers

Figure 8: Map of Alternative Sites Considered for the VIGP

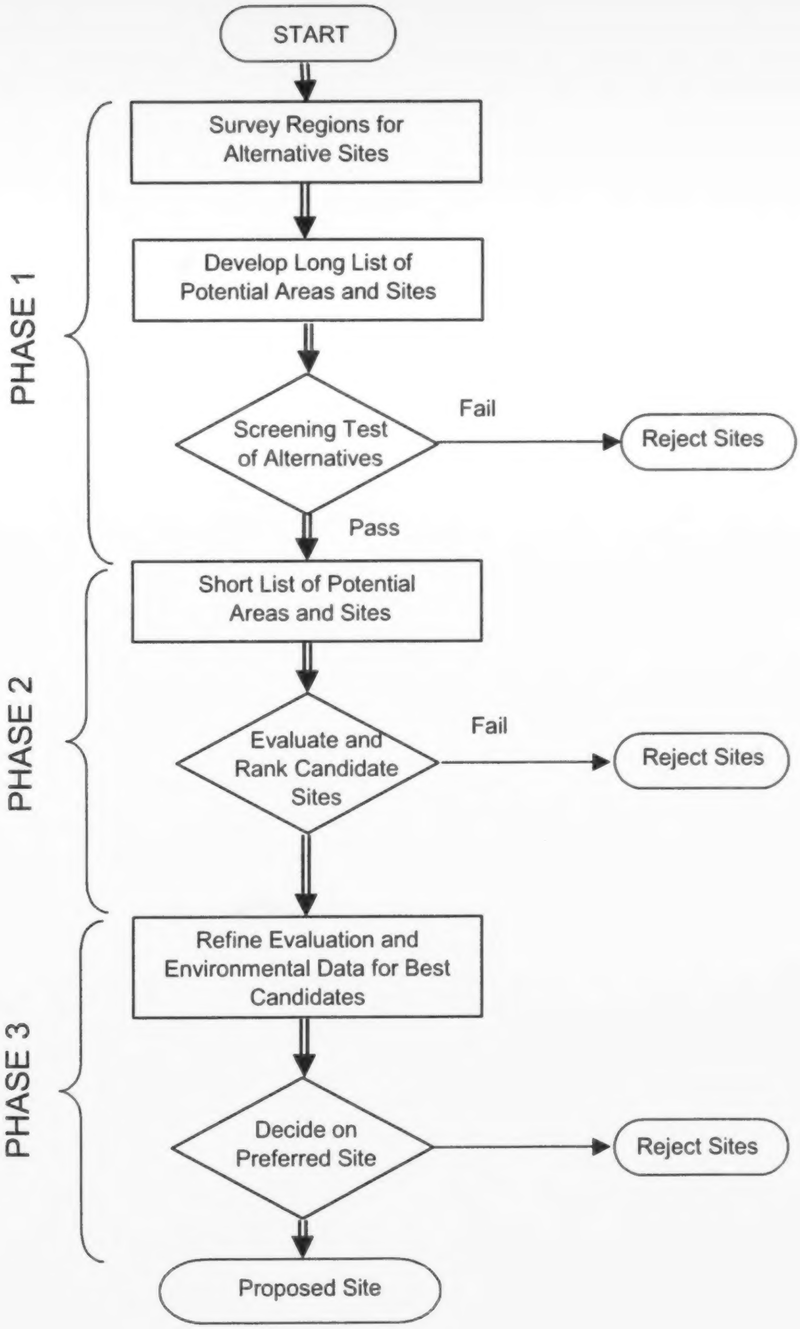
START
Survey Regions for Alternative Sites
Develop Long List of Potential Areas and Sites
Screening Test of Alternatives
Fail
Reject Sites
Pass
PHASE 1
Short List of Potential Areas and Sites
Evaluate and Rank Candidate Sites
Fail
Reject Sites
PHASE 2
Refine Evaluation and Environmental Data for Best Candidates
Decide on Preferred Site
Reject Sites
PHASE 3
Proposed Site

Figure 9: Simplified Schematic of Site Selection Process

6.4.1 Phase 1

The objective of Phase 1 was to develop a long-list of potentially suitable sites that met fundamental criteria for siting the VIGP power plant and the associated natural gas supply, transmission line, water supply and wastewater discharge infrastructure.

Phase 1 started with a survey of regional areas for sites close to power transmission and natural gas pipeline infrastructure, since development at sites close to these systems would minimize the environmental disturbance and infrastructure development costs. The survey for these potential sites was assisted by input from local government planning staff on the location of areas where industrial development is being encouraged, or zoning of properties was consistent with the proposed project.

Identification of sites in Phase 1 was a judgmental process that utilized the applicant's expertise in combination with preliminary information on zoning, engineering, cost, infrastructure requirements, site availability and other factors that influence site selection. Key screening criteria used to identify alternative long-listed sites in Phase 1 were:

- Zoning: The property's zoning should allow the construction and operation of a natural gas-fired power plant.
- Size: For efficient operation, the VIGP requires a minimum area of approximately 4.0 ha (40,000 square metres). An additional 4 ha is needed temporarily during construction for temporary work and material laydown areas. Sites were included that measured 8 ha in area, either on one property or on adjacent properties.
- Proximity to infrastructure: The site should be within 20 km of a natural gas pipeline, a water supply and a suitable location for connection to the power transmission grid, and preferably closer, to minimize environmental disturbance.
- Availability for purchase: The site had to be available for purchase. If it was not, it was immediately eliminated from further consideration.
- Geotechnical/terrain/hazards: The VIGP requires a suitable gradient, appropriate geotechnical conditions to support the loads being transferred to the foundations, and a location that is not exposed to major natural hazards that would prevent the VIGP from being a post-disaster facility. Sites with an existing gradient less than 15% were considered, with preference for sites having a gradient of less than 5%. Geotechnical and hazard aspects of the sites were considered qualitatively.

6.4.2 Phase 2

The sites identified in Phase 1 were examined in more detail using information gathered from site visits, discussions with government agencies, public data sources and a variety of other sources. A numerical evaluation scheme was used to characterize the suitability of each site, considering key engineering and cost factors and potential environmental and health issues associated with the power plant and the development of linear project facilities; namely, the connections to a natural gas supply, a water supply, a wastewater treatment and discharge outfall, and the power grid.

Table 2.2-1 in the EAO Application lists the wide range of site attributes used in the VIGP site evaluation system, grouped into three categories: engineering requirements and cost considerations; potential environmental and health effects of the power plant; and potential environmental and health effects of the linear project components. These site attributes were chosen based on knowledge of the key site attributes that affect engineering design requirements and costs, and environmental or other impacts. The rationale for rating of the various site attributes was developed using professional judgment and experience from past studies of similar projects. To better differentiate between good and poor site characteristics, the rating system assigned a much higher rating to the best site characteristics than to poor site characteristics. All attributes were rated equally. The resulting evaluation provided a reasonable and objective yardstick for ranking the potential suitability of candidate sites and narrowing the list to a small number of "best" sites for site-specific analysis in Phase 3.

6.4.3 Phase 3

Phase 2 of the site selection process identified three promising sites for the VIGP; Phase 3 included analysis to fill gaps in the site information and to enable discussions and negotiations regarding the terms and conditions of purchase of the property. Further engineering, environmental and land analysis was also undertaken to determine more confidently which of these sites was the most suitable. Work undertaken to better characterize the potential environmental and design issues included:

- meetings with staff with local government agencies to identify any concerns about development of the project on the sites;
- reviews of past engineering and environmental studies for the sites to improve the information needed for design, to characterize baseline environmental conditions on and around the sites, to identify and assess the issues associated with development, and to determine site servicing options;
- holding open houses in February 2002 in Cedar and Nanaimo and on Gabriola Island to discuss the site selection process, identify the short-listed sites, and indicate preference to locate the VIGP in the Duke Point area near the Harmac Mill; and
- meetings with property owners to discuss their interest in selling the property and to pursue negotiations on the terms and conditions of sale.

The additional information developed in Phase 3 was used in conjunction with results from earlier phases of the site selection analysis to decide on the preferred site for the VIGP.

6.5 *Site Selection Results*

6.5.1 Phase 1 Site Selection Results

Initial investigations for Phase 1 identified a large number of possible areas and sites that were then reduced to 17 potential sites for the VIGP. These sites appeared to have sufficient size, were close to some (but not necessarily all) the required infrastructure, may be available for purchase and were likely suitable for building in terms of ground conditions, terrain and natural hazards. The location of all of these sites, which are within an area extending 100 km along the eastern side of Vancouver Island, are shown in Figure 8. The 17 sites are located in four different local government jurisdictions: the Regional District of Nanaimo (4 sites); City of Nanaimo (8 sites); Township of Ladysmith (1 site); District of North Cowichan (4 sites).

Upon closer examination of these sites, 10 were determined to be unsuitable mainly because of incompatible zoning for the VIGP, obstacles with gaining access to all the required infrastructure connections, and uncertainty regarding purchase of the property. The remaining seven sites were placed on the site short-list for consideration in Phase 2 of the site selection process. These sites are the named sites shown in Figure 8.

6.5.2 Phase 2 Site Selection Results

Data was gathered to evaluate and rate the seven short-listed sites identified in Phase 1. Information was also obtained to reevaluate the screening level test conducted for the sites in Phase 1 to ensure that the sites met the basic criteria for development. This re-evaluation, using improved site specific information, led to eliminating the Dunsmuir, Peerless Road, and Crofton sites from further consideration for the following reasons:

Dunsmuir
- zoning unsuitable for the VIGP
- major obstacles to development of water supply
- major obstacles to development of wastewater discharge

Peerless Road
- zoning unsuitable for the VIGP
- developable area under 4 ha
- major obstacles to developing water supply/wastewater discharge
- potential impacts to aquatic life and habitat due to clearing

Crofton
- developable area under 4 ha
- insufficient water pipeline capacity to provide the VIGP with the required water supply
- residential area within 100 m of available area for plant site

Applying the evaluation system to the remaining four sites yielded the results shown in Figure 10. A high score indicates a favourable evaluation. The Harmac site had the highest rating, reflecting the advantages of access to existing water supply, wastewater treatment and natural gas supply infrastructure, low new habitat disturbance as a result of past site development, and distance of the site from residential areas.

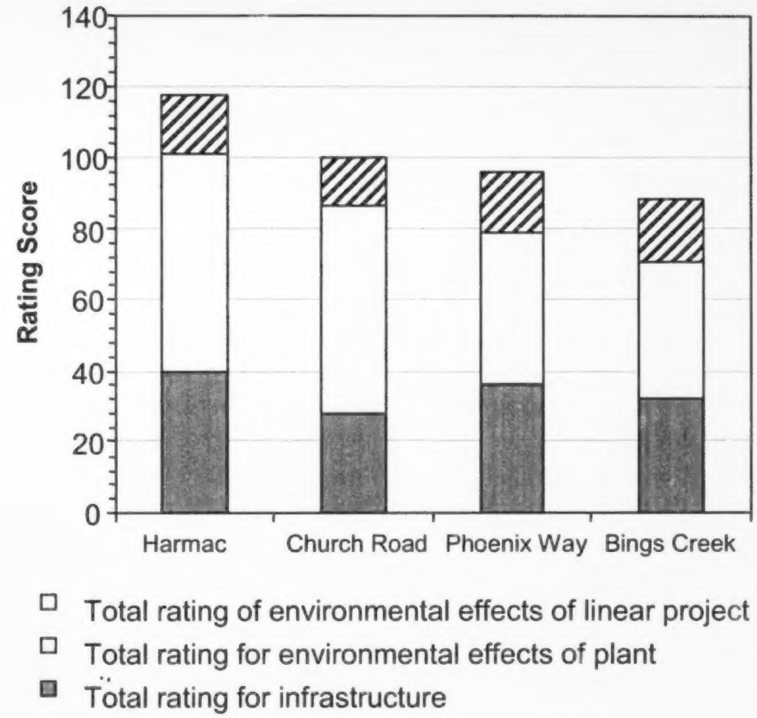

Figure 10: Phase 2 Site Evaluation Results

The next highest ranking sites were those at the Church Road industrial park near Parksville and the Phoenix Way property being rezoned to an industrial park in Duke Point, both of which had similar scores. The Bings Creek site had the lowest evaluation score, resulting mainly from the following disadvantageous features:

- water would need to be provided from the District of North Cowichan's water system, which obtains water from wells beside the Cowichan River—a new well would have to be developed in the well field to supply water needed by the VIGP;
- the District of North Cowichan's sewer system would need to be extended to service the VIGP—there are concerns about the capacity of the piping, the undesirability of dilution of sewage with relatively clean effluent from the VIGP, and the potential effects of effluent discharge to the treatment system and Cowichan Bay; and
- the potential for dispersion and air quality issues associated with the location of the site at the foot of Mount Provost and within the Cowichan River Valley.

The three highest-rated sites progressed to Phase 3 for further analysis and final selection.

6.5.3 Phase 3 Site Selection Results

Further evaluation of the suitability of the Harmac, Phoenix Way and Church Road sites was completed in Phase 3 of the site selection process before settling on the proposed site for construction of the VIGP. The key features of these sites are summarized Table 2.2-2 of the EAO Application.

The Harmac site is 10.1 ha in size and is located immediately south of the Harmac mill's secondary wastewater treatment system and north of Wave Place, the access road to the mill. The site scored the highest in the evaluation of the short-listed sites in large part because of the reduced amount of development and lower environmental impacts that would result with use of existing water supply and wastewater treatment infrastructure, the short pipeline connection to natural gas supply and distance from residential areas. The site is located in an existing industrial area and further development of industrial operations at the site is consistent with the official community plan.

VIEC pursued negotiations with Pope & Talbot, while analysis continued to finalize the evaluation of the remaining sites that advanced from Phase 2. Negotiations were undertaken to secure an option to purchase the property, and to develop agreements on water supply, wastewater treatment and other technical matters. VIEC has now purchased the property, and has reached an agreement for the supply of water to the VIGP and the treatment and discharge of effluent from the VIGP.

The Church Road site rated second highest in the site evaluations. The site is 81 ha in area and is for sale in various sized lots for industrial development, although it is presently unzoned. The site is relatively flat and located in the remains of a sand and gravel extraction operation, which cleared the land and extensively disturbed the original soils and habitat. It is located between the Island Highway (Hwy 19) on the north and the E&N railway line to Port Alberni and the Alberni Highway (Hwy 4) on the south. The site is 1.8 - 2.1 km from residential areas in Parksville and is 0.4 - 0.7 km from rural residents and commercial businesses on Church Road and the Alberni Highway. Roads on the site have been aligned and finished to subgrade. The site rated fairly highly because of the extent of current clearing and development, its location in a fragmented area between linear developments that isolate it at some distance from residential or commercial developments, and the distance of the site from elevated terrain or other impediments to dispersion of emissions.

The main technical and regulatory obstacles to development of the VIGP at Church Road are the lack of servicing infrastructure for water supply and wastewater discharge. These two areas were investigated further, a process that included discussions with staff at the Regional District of Nanaimo (RDN) and a review of available water supply studies. At the RDN's request, its consultant reviewed the capacity of the French Creek wastewater treatment plant and the outfall to the ocean, which is the closest municipal facility to the Church Road site. It was found that there is insufficient excess capacity in the plant and the outfall to handle the wastewater flow from the VIGP. Consequently, if the VIGP were to locate at the Church Road site, the French Creek facilities would have to be expanded, or a new separate outfall would need to be constructed. With regard to water supply to the Church Road site, discussions with RDN staff and review of the extensive studies used in support of development of the Arrowsmith dam and a regional water supply system indicate that:

- ☐ there are no firm plans for supply of water to the Church Road area by the Arrowsmith Water Service Joint Venture (Regional District of Nanaimo, City of Parksville and Town of Qualicum Beach) which has a conditional water licence for diversion from the Englishman River and storage in Arrowsmith Lake;
- ☐ although the 20 year capital plan identified a new water supply pipeline alignment adjacent to the new Island Highway between Parksville and Qualicum Beach (close to the Church Road site) that would draw water from a new intake structure close to the confluence of the Englishman River and the South Englishman River, it is presently unknown when, or if, these facilities would be developed; and
- ☐ the licensed water diversion is allocated to current and future domestic water supply to the Arrowsmith Water Service Joint Venture communities, and it is unlikely that water would be made available to the VIGP for industrial use.

Based on the significant technical, environmental and regulatory issues associated with water supply and wastewater discharge for the Church Road site, this site was eliminated from further consideration.

The Phoenix site is 26.1 ha in total area and has a developable area of about 21 ha. The rezoning plan allows for about 1.3 ha to remain in the agricultural land reserve for the location of a shared constructed wetland. The western end of the property contains an arboretum planted by MacMillan Bloedel for experimentation with tree species and is to be transferred to the City of Nanaimo for park use. The owner has applied to rezone the site for heavy industrial use, with the intention of developing seven industrial lots.

Water could be supplied to the Phoenix site by the Greater Nanaimo Water District using existing infrastructure. Wastewater from the VIGP could be treated on-site and piped to tie into the new deep-water outfall in Northumberland Channel installed opposite the RDN's Duke Point Wastewater Treatment Plant. This outfall was installed by Westcoast Reduction and is being granted to the RDN, which will become the long-term operator. The intent is for the outfall to be a shared-use facility for use by other operations in Duke Point under individual effluent discharge permits from the Ministry of Water, Land and Air Protection. There are some operational concerns about discharging to a single outfall regulated with multiple effluent permits and outfall capacity limitations during peak seasonal flows from Westcoast Reduction's plant that could limit the VIGP's discharge.

The Phoenix site is attractive because it is located in an industrial area away from residential development, has access to water supply and wastewater discharge infrastructure, and has sufficient size to be convenient for the VIGP and allow a buffer area around the facility. Negotiations were successfully undertaken with the owner and an option to purchase the property was agreed. However, rezoning of the property to allow heavy industrial use was not completed.

The Harmac site is concluded to be the best site for the VIGP, based on a thorough consideration of engineering design, cost, environmental, health and socio-economic factors, and is the site proposed for development in this application.

6.6 *Project Components*

The VIGP comprises the construction, start-up and operation of the following facilities:

- ☐ a natural gas fired combined cycle power plant with a nominal base power output of 265 MW without duct firing, or a peak power output of 295 MW with duct firing;
- ☐ a 440 m long, 219 mm diameter natural gas service line supplying the plant with natural gas routed from Centra's existing Harmac lateral pipeline;
- ☐ an 850 m water supply pipeline within an existing right-of-way beside Wave Place to bring water from the existing Harmac mill water reservoir to the plant;
- ☐ a 325 m pipeline on the plant site area to transport wastewater from the VIGP to the existing Harmac mill wastewater treatment system, where it will be combined with mill effluent, treated to meet effluent permit requirements, then discharged to Northumberland Channel through an existing outfall;
- ☐ an upgrade of the existing power transmission line circuits that provide power to industrial users in the Duke Point area, involving the addition of a new 3 km circuit from the Harewood tap at the mainline to Harewood substation and the upgrade of the 6 km portion of the circuit from Harewood substation to the VIGP;
- ☐ temporary construction space and works needed during construction and start-up of the project, with laydown area for the plant to be located on the proposed site and work space for the linear developments to be in the existing rights-of-way or on developed land.

Figure 11 shows the location of the proposed plant site, the natural gas service line from the existing Harmac lateral and the existing 9 km transmission line that will be upgraded to handle the power generated by VIGP. The plant site is within the current boundaries of Pope & Talbot's Harmac operations, which will provide water to the plant and treat and discharge wastewater from it.

For details of the plant and site layout, see Figures 3.1-2 and 3.1-3 in the EAO Application.

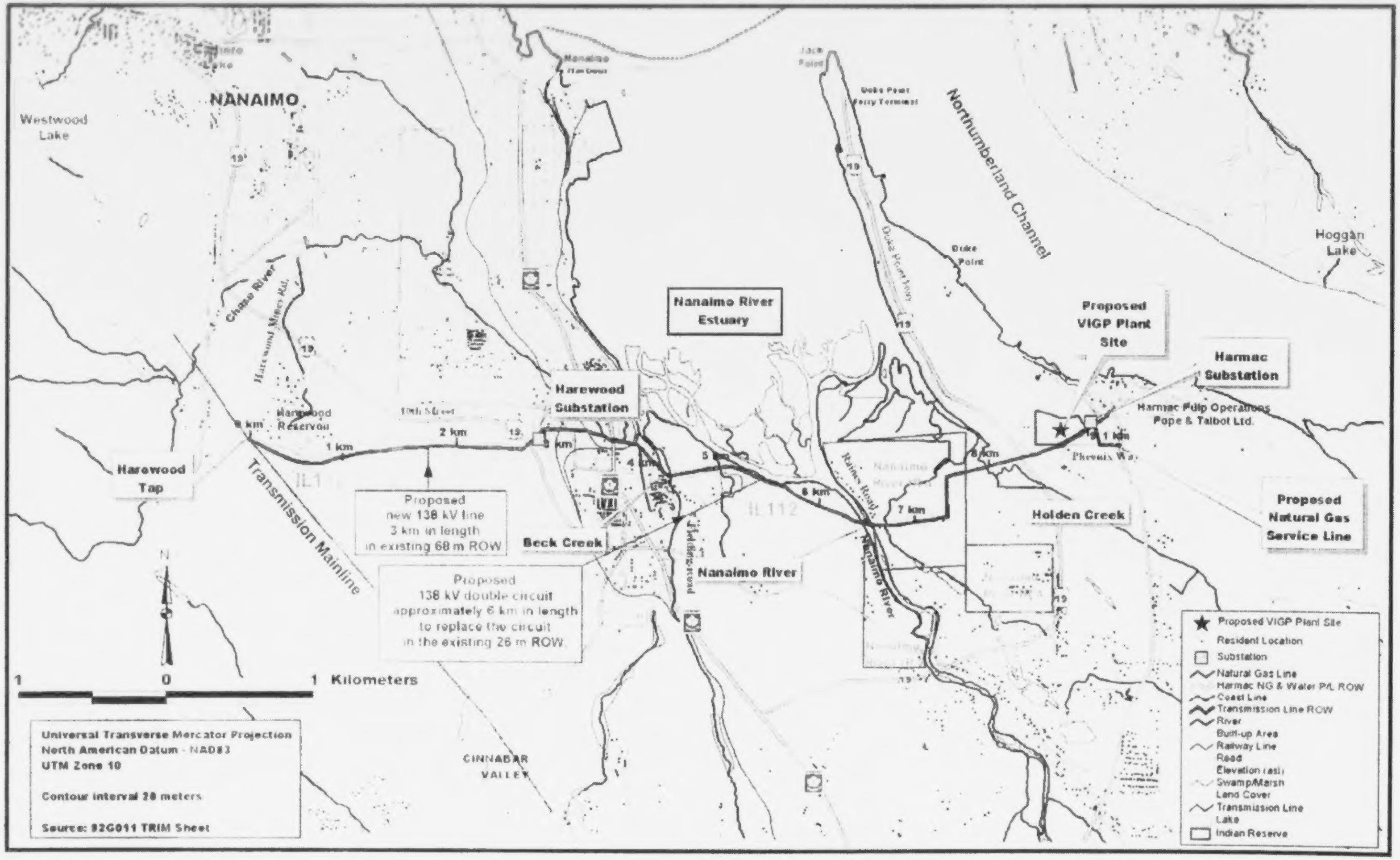
NANAIMO
Westwood Lake
Nanaimo Harbour
Jack Point
Duke Point Ferry Terminal
Northumberland Channel
Duke Point
Duke Point Hwy
Hoggan Lake
Nanaimo River Estuary
Proposed VIGP Plant Site
Harmac Substation
Harmac Pulp Operations Pope & Talbot Ltd.
Phoenix Way
Proposed Natural Gas Service Line
Holden Creek
Harewood Substation
Chase River
Harewood Mines Rd.
Harewood Reservoir
11th Street
Harewood Tap
Transmission Mainline
IL1
IL112
0 km
1 km
2 km
3 km
4 km
5 km
6 km
7 km
8 km
1 km
Proposed new 138 kV line 3 km in length in existing 68 m ROW
Proposed 138 kV double circuit approximately 6 km in length to replace the circuit in the existing 26 m ROW
Beck Creek
Nanaimo River
Raines Road
Fielding Road
CINNABAR VALLEY
19
19A
N
1 0 1 Kilometers
Universal Transverse Mercator Projection
North American Datum - NAD83
UTM Zone 10
Contour interval 20 meters
Source: 92G011 TRIM Sheet
Proposed VIGP Plant Site
Resident Location
Substation
Natural Gas Line
Harmac NG & Water P/L ROW
Coast Line
Transmission Line ROW
River
Built-up Area
Railway Line
Road
Elevation (asl)
Swamp/Marsh
Land Cover
Transmission Line
Lake
Indian Reserve

Figure 11: Detailed Map of Proposed VIGP Plant Site and Linear Components

The proposed VIGP power plant will have a nominal power output of 265 MW without duct firing and 295 MW with duct firing, net of the power requirements of ancillary equipment. A high-efficiency combined cycle configuration will be used which involves integrated operation of a combustion turbine generator with a nominal rating of 170 MW and a steam turbine generator with a nominal rating of 95 MW. A summary of the key design parameters for the plant is provided in Table 9.

Nominal Power Output:	
Without Duct Firing:	
Combustion Turbine:	170 MW
Steam Turbine:	95 MW
Rated Total Power Output:	265 MW
With Duct Firing:	
Combustion Turbine:	170 MW
Steam Turbine:	125 MW
Rated Total Power Output:	295 MW
Supply Voltage to BC Hydro:	138 kV
Primary Fuel:	natural gas
Backup Fuel:	none
Major Indoor Equipment:	combustion turbine and generator steam turbine and generator feedwater treatment
Major Outdoor Equipment:	heat recovery steam generator exhaust stack (45.7 m above ground) cooling tower switchyard water tank
Emission Controls	dry low NO_x and low CO combustor SCR (aqueous ammonia injection)
Site Area:	10.1 ha

Table 9: Design Parameters for VIGP Plant

The process flow for the plant's main components is shown schematically in Figure 12, with the components numbered and described on the following page.

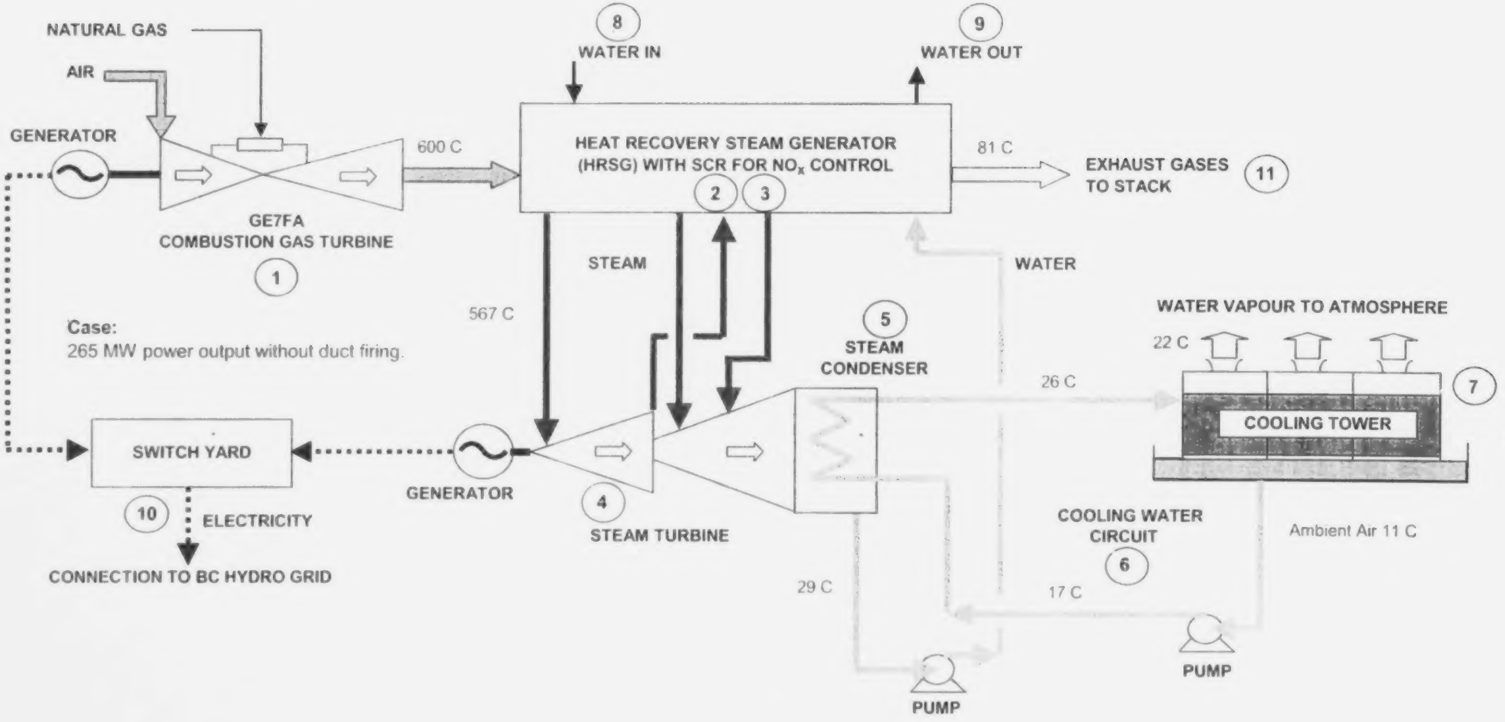
NATURAL GAS
AIR
GENERATOR
GE7FA
COMBUSTION GAS TURBINE
①
600 C
⑧
WATER IN
⑨
WATER OUT
HEAT RECOVERY STEAM GENERATOR
(HRSG) WITH SCR FOR NO_x CONTROL
②
③
81 C
EXHAUST GASES
TO STACK
⑪
STEAM
567 C
WATER
Case:
265 MW power output without duct firing.
⑤
STEAM
CONDENSER
WATER VAPOUR TO ATMOSPHERE
22 C
26 C
⑦
COOLING TOWER
SWITCH YARD
GENERATOR
④
STEAM TURBINE
⑩
ELECTRICITY
CONNECTION TO BC HYDRO GRID
COOLING WATER
CIRCUIT
⑥
Ambient Air 11 C
29 C
17 C
PUMP
PUMP

Figure 12: Simplified Process Schematic for the VIGP Power Plant

The components in Figure 12 are itemized as follows:

1. GE 7FA natural gas fired combustion turbine generator (CTG) equipped with dry low NO_x (and low CO) combustors;
2. heat recovery steam generator (HRSG) with duct burners that will provide additional heat input and steam generation during peak electricity demand periods;
3. selective catalytic reduction (SCR) unit with an aqueous ammonia storage and handling system to reduce NO_x emissions to the atmosphere;
4. single condensing steam turbine generator (STG);
5. surface condenser,
6. cooling water circuit
7. wet cooling tower to condense the exhaust steam from the STG and vent this heat to the atmosphere;
8. water pipeline from the Harmac mill and a feedwater treatment system;
9. wastewater collection system and pipeline to the Harmac mill wastewater treatment system;
10. electrical switch yard; and
11. main stack.

The steam power cycle will be designed to achieve high efficiency. The HRSG will generate high pressure steam at 11,467 kiloPascals (kPa) and 563° C, as well as intermediate pressure steam blended with hot reheat at 2,771 kPa and 566° C. Natural gas-fired duct burners will be installed in the duct at the inlet to the HRSG to provide operational flexibility by allowing the inlet gas temperature to be increased and additional steam and electricity to be generated when needed to meet power demand.

6.7 *Material and Energy Balances*

Nominal material and energy balances have been developed from preliminary engineering work underway for the proposed plant. This information has been used to determine an energy balance and inputs and discharges for the plant pertinent to the environmental impact assessment. See subsection 3.2.2 of the EAO Application.

6.8 *Description and Specifications of Major Plant Equipment*

6.8.1 Gas Combustion Turbine Generator

An advanced, dry low NO_x (and low CO) General Electric 7FA CTG will be used to carry out the controlled combustion of natural gas, which is converted into mechanical energy as the combustion gases at high pressure expand to lower pressure through the turbine. The mechanical energy drives both the electric generator, and the combustion turbine compressor, which provides air for combustion. Air needed by the CTG is first filtered, then supplied through ductwork to the turbine's compressor. Air and natural gas are injected into a staged pre-mixed combustor under carefully controlled conditions and ignited. The gases produced expand through the turbine, generating the mechanical energy for the generator and the air compressor. This technology first became available in the late 1980s, and has since been developed to improve performance and achieve low emission levels. A summary of the reliability of the F technology generators is provided in Appendix G.

The CTG system consists of a stationary combustion turbine generator, supporting systems, and associated auxiliary equipment. For safe and reliable operation, the following accessories will be included: inlet air filters; lube oil cooler; compressor wash system; fire detection and protection system; and fuel heating system.

6.8.2 Heat Recovery Steam Generator

The HRSG will recover energy from the turbine exhaust gases. It is a three-pressure, natural circulation unit equipped with inlet and outlet ductwork, insulation, lagging, and an exhaust stack. It will be equipped with low NO_x natural gas-fired duct burners to increase steam output and associated generation capability when needed to meet electricity demand. Duct burners will also provide greater operating flexibility and improved steam temperature control.

Major components include: a low pressure (LP) economizer; LP drum; LP evaporator; LP superheater; intermediate pressure (IP) economizer; IP evaporator; IP drum; IP superheater; high pressure (HP) economizer; HP evaporator; HP drum; and HP superheaters. The LP economizer receives condensate from the condenser hot well from the condensate pumps. The LP economizer is the final heat transfer section to receive heat from the combustion gases prior to their being exhausted to the atmosphere.

A selective catalytic reduction (SCR) module will be integrated into the HRSG downstream of the duct burners, where the gas temperature regime is optimal for the chemical reaction of NO_x with ammonia to produce nitrogen and water vapour. This emission control equipment will reduce the NO_x concentration in the combustion gases prior to discharge to the atmosphere. An aqueous ammonia handling, storage and flow control system will be included in the plant for the SCR.

The HRSG transfers heat from the exhaust gases to the feed water to produce steam for the steam turbine operation. The feed water is converted to superheated steam and delivered to STG at the high, intermediate and low pressures. The use of multiple steam delivery pressure increases the cycle efficiency and flexibility.

Boiler water quality will be monitored at various points in the HRSG steam cycle and provide sufficient data to operating personnel for detection of deviations from control limits so that corrective action can be taken. The samples will be routed to a sample panel where pressure and temperature will be reduced as required. At the sample panel, samples will be directed to automatic analyzers for continuous monitoring. Grab samples will be provided for wet chemical analysis. Monitored values will be indicated at the sample panel. Automatic analyzers will monitor conductivity, pH and specific conductance.

6.8.3 Steam Turbine Generator

The STG will consist of: a reheat condensing steam turbine; gland steam system; lubricating oil system; hydraulic control system; and steam admission/induction valving. Steam from the HRSG HP, IP and LP superheaters will enter the associated steam turbine sections through the inlet steam system. The steam expands through the turbine blading, driving the generator. On exiting the turbine, the steam is condensed under vacuum in the condenser to extract available energy.

6.8.4 Cooling Water System and Cooling Tower

The plant cooling system will consist of a surface condenser, cooling tower, and cooling water system. Steam under vacuum will leave the low pressure section of the steam turbine as wet saturated steam, then pass through a surface condenser, releasing heat to the cooling water as the steam condenses. Because the steam turbine exhausts under vacuum (nominally 5 kPa absolute pressure compared to 101.3 kPa ambient pressure at sea level) the temperature of the condensate from the steam turbine will be low, ranging approximately from 26° C in winter to 38° C in summer. The condensate will then be delivered to the HRSG feed water system for reuse. The warm cooling water will circulate through a mechanical-draft cooling tower that uses electric motor-driven fans to draw air through a spray of cooling water droplets. The heat removed in the condenser will be discharged to the atmosphere by heating the air and by evaporation of some of the cooling water. The cooling tower will have multiple variable-speed fan-driven cells. Operation at less than full load will be accommodated by turning off one or more cells or by slowing or turning off the fans.

6.8.5 Water Supply and Feedwater Treatment

Makeup water for the cooling water system will be taken from the water supply header. A chemical feed system will supply conditioning chemicals to this water to minimize corrosion and control the formation of mineral scale and biofouling. Depending on raw water quality, sulphuric acid may be fed into the circulating water system for alkalinity reduction to control formation of scale in the piping within an acceptable range. The acid feed equipment, if required, will consist of a bulk sulphuric acid storage tank and two full-capacity sulphuric acid metering pumps. To further inhibit scale formation, a scaling inhibitor solution may be fed into the circulating water system in an amount proportional to the circulating water blowdown flow. The inhibitor feed equipment will consist of a chemical solution bulk storage tank and two inhibitor metering pumps. To prevent biofouling in the circulating water system, the water will be chlorinated and the chlorine level will be at a level similar or lower than that used in drinking water.

Service water includes all water uses at the plant, except for the circulating water previously discussed and the demineralized water used in the HRSG.

Makeup water for the HRSG will be taken from the raw water supply. The expected treatment methods may include filtration, reverse osmosis, and demineralization to improve water quality, and will be selected during final plant design. The demineralized water will be stored in a storage tank. This capacity provides approximately 24 hours of supply, during interruption of the normal supply of water from the demineralized water supply system. HRSG makeup water will be drawn from the demineralized water storage tank.

The demineralized water in the HRSG will be conditioned to minimize corrosion and scale formation. A system will feed an oxygen scavenger to the feedwater for dissolved oxygen control and sodium phosphate or other commonly used water treatment chemicals to the feedwater for pH control.

6.8.6 Switchyard

An electrical switchyard will be installed on the plant site and include generator step-up transformers, a station-fed transformer, 138 kV circuit breakers, lightning arrestors, disconnect switches and associated switches required to support the connection to the BC Hydro grid. The interconnection of this switchyard to the BC Hydro grid is discussed in section 6.11.

6.8.7 Plant Auxiliaries

A lighting system will provide illumination for operation under normal conditions and for egress under emergency conditions. The system will include emergency lighting to perform manual operations during an outage of the normal power source.

The electrical system is susceptible to ground faults, lightning, and switching surges that result in high voltage hazards to site personnel and electrical equipment. A station grounding system will be designed to provide an adequate path to dissipate current created by these events. The grid spacing will be such that safe voltage gradients are maintained. Bare conductors will be installed below grade in a grid pattern. Ground resistivity readings will be used to determine the necessary numbers of ground rods and grid spacing to ensure safe step and touch potentials under severe fault conditions. Grounding stingers will be brought from the ground grid to connect building steel and non-energized metallic parts of electrical equipment.

A Distributed Control System (DCS) or Integrated Control System (ICS) will be included in the plant to provide modulating control, digital control, monitoring and indicating functions for the plant power block systems. The following functions will be provided:

- control of the STG, CTG, HRSG and other systems;
- monitor of controlled plant equipment and process parameters and delivery of this information to plant operators;
- control displays for signals generated or received;
- consolidated plant process status information through displays presented in a timely and meaningful manner;
- alarms; and
- storage and retrieval of historical data.

The distributed control and information system will be a redundant microprocessor-based system. The DCS will have a functionally distributed architecture comprising a group of similar redundant processing units linked to a group of operator consoles and the engineer workstation by redundant data highways. Each processor will be programmed to perform specific dedicated tasks for control information, data acquisition, annunciation and historical purposes. By being redundant, no single processor failure can cause or prevent a unit trip.

The DCS will interface with the digital governor control systems furnished by the combustion and steam turbine suppliers to provide remote control capabilities, as well as data acquisition, annunciation and historical storage of turbine and generator operating information. The system design will preclude a single device failure from significantly affecting overall plant control and operation. This also will allow critical control and safety systems to have redundancy of controls, as well as an uninterruptible power source.

The cathodic protection system will be designed to control the electrochemical corrosion of designated metal piping buried in the soil. The freeze protection system will provide heating to protect various outdoor piping, gauges, pressure switches, and other devices from freezing.

6.9 *Geotechnical Design*

Geotechnical conditions are expected to be favourable with respect to the development of the VIGP. Site reconnaissance and nearby subsurface exploration indicate that the project area is underlain with bedrock at shallow depths. This bedrock has provided suitable foundation bearing conditions for the heavy industrial structures associated with the nearby Harmac mill.

Earthquakes are a natural hazard on Vancouver Island and parts of British Columbia. Current seismic design aspects of construction in British Columbia are based on the

1998 British Columbia Building Code, in which design criteria are provided in Section 4.1.9, "Live Loads due to Earthquakes," and in Commentary J, a supplement to the 1990 National Building Code of Canada (NBCC). The VIGP will be designed in accordance with the objectives and requirements of the NBCC.

6.10 *Environmental Impacts and Proposed Environmental Controls*

See Section 3.2.2 of the EAO Application.

6.11 *Electrical Transmission Line*

This section discusses the on-Island transmission upgrades that are likely to be needed to accommodate the power generated by the VIGP plant. Refer to Figure 11 for locations described in this section.

6.11.1 General Description and Location

There is currently one 138 kV transmission line, circuit 1L112, supplying electricity from BC Hydro's Jingle Pot Substation[74] to the Duke Point area for the Harmac mill, Island Phoenix mill, and the Nexen plant loads. The Jingle Pot Substation also supplies, via circuit 1L138, electricity to the Harewood Substation for local residential and commercial loads. If unchanged, this existing transmission system cannot accommodate the power generated by the new generating station.

Jingle Pot Substation is located just inside the Nanaimo City boundary on Jingle Pot Road. Harewood Substation is also located within the Nanaimo City limits off Tenth Street. The customer substations of Nexen, Harmac and Island Phoenix are all located in the Duke Point industrial area.

Four transmission lines exit on the south side of Jingle Pot Substation:

- 138 kV circuit 1L112, a wood pole line which runs to the Harmac mill, Island Phoenix mill and Nexen plant—this circuit is approximately 15 km long;
- 138 kV circuit 1L138, a wood pole line that runs to Vancouver Island Terminal (VIT) near Duncan—approximately 6 km south of Jingle Pot Substation, this circuit taps into the Harewood Substation; and
- 138 kV circuits 1L109 and 1L122, two lines on double circuit steel lattice towers—these circuits terminate at VIT.

The transmission line project upgrade for the VIGP is divided into two segments:

- Harewood tap junction to Harewood Substation, approximately 3 km east of the tap junction.

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[74] Not shown on Figure 11 (to the north of Westwood Lake).

- Harewood Substation to the Harmac mill, Island Phoenix mill, Nexen plant, and the VIGP, approximately 6 km east of Harewood Substation.

Nine transmission options were identified to transfer the additional capacity from the VIGP to the BC Hydro system. The transmission options range from: upgrading the existing circuit 1L112; building a new 138 kV line; building two 138 kV circuits on a double circuit line; and building a single circuit 230 kV line. The substation options examined to accommodate the new transmission included additions and upgrading of equipment at the Jingle Pot Substation and the Harewood Substation and the possible construction of a new substation in the vicinity of the VIGP plant.

Based on the analysis of options, BC Hydro proposes to upgrade the existing circuit 1L112 from the Harewood substation to the Duke Point area. The upgrade will be to a 138 kV double circuit that can carry 400 MW in each circuit, one circuit to supply Harmac, Island Phoenix and Nexen directly, the other circuit to connect to the VIGP. BC Hydro also proposes to build a new 3 km 138 kV tap line from circuit 1L138 to loop into the Harewood substation. The type of work involved in this upgrade is:

- Install 3 km of new 138 kV line in the existing BC Hydro right-of-way to (ROW) the Harwood substation from the Harewood Tap at the existing circuit 1L138 main line. The existing circuit 1L112 will terminate at the Harewood substation;

- Install a new double circuit line and towers in the existing BC Hydro ROW to replace 6 km of circuit 1L112 to provide two 400 MW lines. Because of the narrow ROW corridor in this segment, a temporary by-pass line will be built in the ROW to carry one or two phases of the existing 1L112 to maintain continuous electrical supply to these customers, then removed once the permanent towers and circuit have been commissioned. Also included in the work is the addition of a 7-breaker 138 kV ring bus to terminate existing lines, existing transformers, and new lines at Harewood Substation.

6.11.2 Transmission Line Design

Structural requirements for the line are influenced by the conductor selection. However, after the necessary conductor strength and clearance requirements of the voltage are met, various structure, material and configuration options are available. These options can provide variation in the general appearance of the line and can affect the amount of necessary vegetation clearing along the right-of-way. Not only is it the function of the structure to keep the conductors at a safe operating distance above the ground, but each of the three conductors must also be kept a safe operating distance apart. Clearances from the conductors to the structure and guys must also be maintained.

Traditionally, most of the wood poles used in BC Hydro's transmission system use Western Red Cedar. However, for this project, the use of single piece, 12-sided steel poles is planned. These poles, while generally more expensive than wood, have greater strength and need less maintenance.

The existing 9 km 138 kV transmission line to be upgraded for VIGP is situated on BC Hydro ROWs that vary from 26 m to 68 m in width. From Harewood Tap to Harewood Substation the width is 68 m; from there to Harmac the width is 26 m. There are no identified areas of hazards along the proposed route. The operating experience of 1L112 is such that there is no reason to consider that a double circuit option would be less reliable than two single circuit lines. The ROW from Harewood station to the substations in the Duke Point area can accommodate only one circuit or a double circuit line, not two single circuit lines.

To ensure the safe reliable operation of a transmission line, any vegetation that could come into close proximity of the conductors must be removed. The amount, or width, of clearing required within the existing ROW and the need for removal of danger trees depends on: ground slope; horizontal conductor spacing (distance to outside conductor from centreline); conductor swing; conductor height above ground; tree height; tree species and growth rate; health or condition of the tree; and line reliability requirements.

For example, in areas with short, slow growing trees, the clearing boundaries may be narrow. In areas with tall timber and steep ground slopes, the clearing boundary will likely be wider. In areas where the conductor is well above the average tree height, particularly across gullies and streams, clearing is often not required. Sometimes in areas where clearing width is a concern, thinning or trimming of selected trees may also be carried out. Trees taller than the predominant tree height are also individually removed if they pose a hazard to the transmission line. These are referred to as danger, or hazard, trees. Removal of hazard trees affecting the temporary by-pass line will be done under the supervision of an arborist. Access to upgrade the transmission line will be by roads present along the existing ROW.

Within the restrictive 26 m ROW, it will be necessary to construct one or more temporary bypass lines to carry one or two phases of the existing circuit from Harewood Substation to Harmac, Island Phoenix and Nexen customers. This is necessary to maintain continuous electrical supply to these customers since no lengthy outages can be planned. Relocating the phases of the existing line will allow for the new double circuit steel poles to be constructed near the centreline of the existing ROW.

6.12 *Natural Gas Supply*

6.12.1 General Description and Location

Natural gas required by the plant will be provided from the GSX Project, via the Centra system. A short service line will be installed to connect the plant to the existing six-inch diameter Harmac lateral to the mill. The tie-in to the Harmac lateral will be close to the Phoenix Way overpass.

The new pipeline routing will be in a westerly direction on the north side of the existing Centra distribution ROW, turning northwest just before an existing underground 3-phase power line. This line runs south from the Weyerhaeuser transformer station located close to the southeast corner of the Harmac site to Wave Place, then west towards Hooker

Road. The pipeline will then run parallel to the underground power line under Wave Place in a northwesterly direction to a point just north of the transformer station, then between the transformer station and substation in a westerly direction to the plant.

A gravel service road will be constructed, and share the ROW with that used for the natural gas service line to provide vehicle access from Wave Place into the Weyerhaeuser transformer station.

At the plant site, natural gas will flow through gas separator/filtering equipment, a fuel gas heater, gas pressure regulating equipment and flow metering equipment before entering the combustion turbine. This equipment will be located in a fenced area approximately 25 m^2 in the southeast corner of the proposed VIGP site. Additional pressure reduction equipment and a low pressure gas distribution system will provide gas for the HRSG duct burner systems.

6.12.2 Pipeline Design

The pipeline maximum pressure will be 2160 psig. The pipeline will be approximately 440 m long and will be buried at a safe depth in accordance with accepted practice. The maximum supply pressure to the plant, downstream of the regulation, will be 500 psig, a suitable inlet pressure for the gas turbine. It should not require on-site compression equipment. The pipeline crossing of Wave Place will be developed by boring underneath the road. The pipeline systems will be designed and constructed in accordance with the latest edition of the relevant Canadian Standards Association codes and regulations.

6.13 *Construction Plans*

6.13.1 Construction Management

Engineering, construction and operation contractors will provide design, construction, and start-up services for the facility. Subcontractors will be selected by the general contractor for specialty work as needed. Detailed construction plans will be developed by the engineering and construction contractors for review and approval by VIEC, the VIGP will meet any requirements of appropriate permitting agencies. A construction manager will oversee all activities of the construction contract and require compliance with environmental, engineering, construction and safety standards, permits, and conditions of the project approval certificate.

6.13.2 Site Preparation and Construction Areas

The project site is cleared of trees where construction activities will take place. Hooker Road currently provides access to the west side of the property, while secondary access is available from Wave Place. Initial site development will involve clearing, grading, soil stabilization and application of aggregate surfacing. Construction activities will also include the following: upgrade the stretch of Hooker Road, adjacent to the project site, to municipal standards; construct an access road on the property according to the site plan;

and prepare a laydown area needed during construction. This area will be landscaped after construction is completed.

Construction activities will be planned to mitigate potential environmental impacts. Environmental performance specifications will be prepared for the engineering and construction contractor and cover adherence to all applicable permits, use and handling of approved materials, construction practices and in particular, current best practices for environmental protection during construction, housekeeping, proper disposal of wastes, and conformance to WHMIS and other pertinent regulations. The contract will state the responsibilities of the contractor and subcontractors and specify the environmental monitoring requirements that must be applied on the construction sites.

All special wastes will be handled, stored, transported, treated, and disposed of in accordance with applicable national, provincial, and local regulations; procedures will be established to ensure proper storage, labelling, handling, and disposal of hazardous wastes in accordance with Workers' Compensation Board and WHMIS regulations, including procedures for record keeping and waste minimization.

6.13.3 Schedule

The scheduling of the VIGP has proceeded under, and is integrally related to, the Island gas generation strategy arising from the IPP Review Panel Report. (See discussion at section 1.5 of this application.) Other key factors that relate to scheduling include electric system reliability planning criteria (resulting in the expected end-of-life of the HVDC system), lead times for turbine construction, the decision not to spend further amounts on project development until after the GSX Project and other approvals are obtained, and the time required to qualify and select an IPP to assume the construction and/or operation of the power plant.

Given all these considerations, VIEC has scheduled July 1, 2006 as the in-service date for the VIGP. The relevant timelines and dates by which critical events must take place in order to achieve this schedule are shown in Figure 13.[75] Key processes include obtaining an environmental assessment certificate—shown in Figure 13 as June 2003;[76] obtaining a CPCN and related orders from the Joint Review Panel for the Canadian portions of the GSX Project—based on a hearing that commenced February 24, 2003 and estimated to take eight months from commencement to decision; and BCUC review of this application, based on a March 10, 2003 filing date and an estimated eight-month review period. Assuming the necessary approvals are obtained, a further eight months is allowed to conduct a competitive IPP selection process, with the selected IPP completing the project within a 24-month construction and commissioning period.

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[75] Best estimate as of March 3, 2003.

[76] Pursuant to the EAO Scoping Order (see Appendix D) and allowing 45 days for ministerial approval

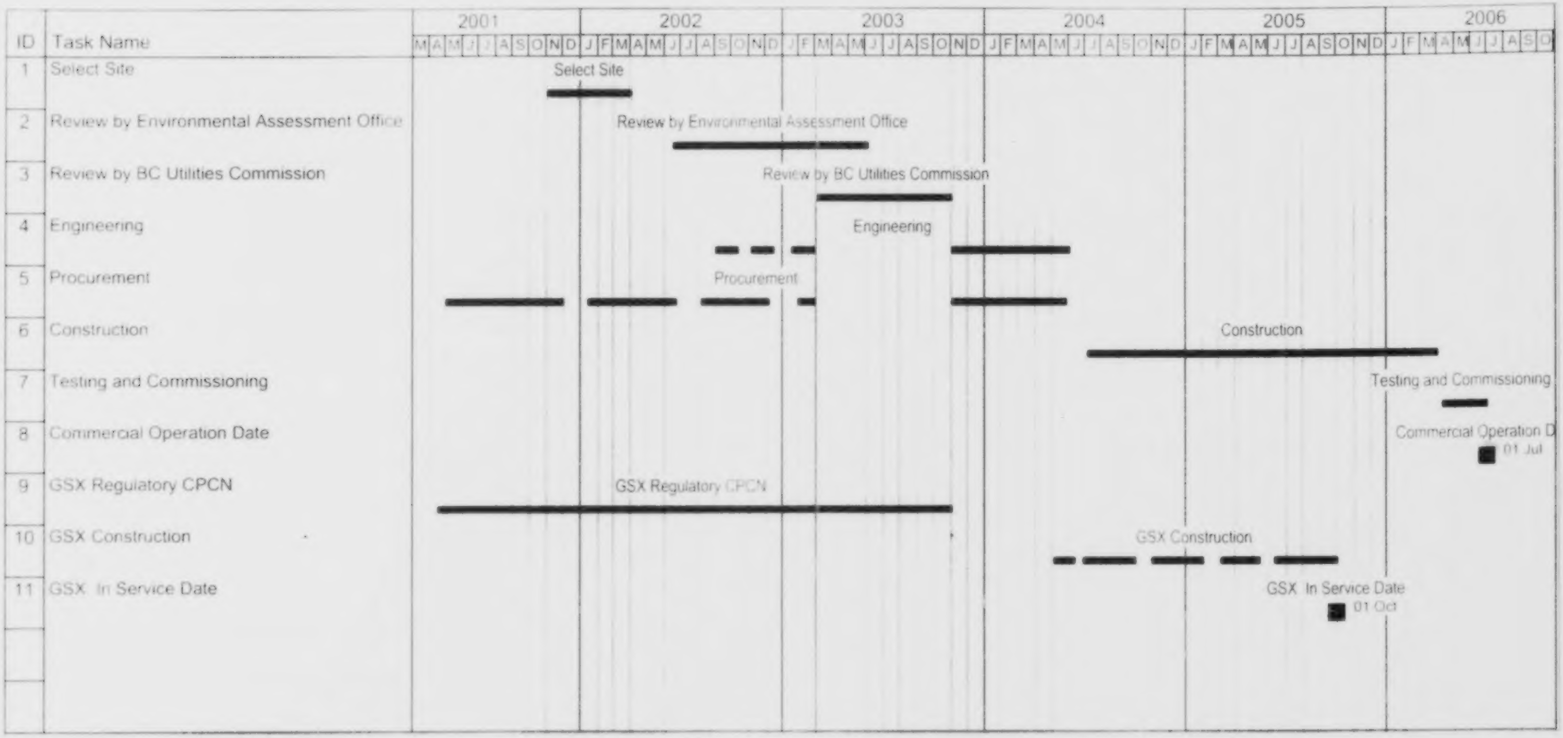

Figure 13: VIGP Project Schedule

6.13.4 Workforce Estimates

The VIGP will provide 239 person-years of construction employment. Peak workforce at the site is estimated at 250 people. Where possible, construction workers will be hired from the local workforce. When the power plant is operational it will provide full-time employment for 20 people for the projected 25-year operating life of the power plant.

6.13.5 Capital and Operating Costs

The project cost is estimated at $340 million (2002 dollars). The final cost will not be determined until all contracts are signed and all equipment purchased. Direct operating and maintenance costs, excluding natural gas, are estimated at $17.8 million yearly (2006 dollars), including $2.3 million per year for wages and benefits. The largest operating cost, natural gas, is discussed in subsection 5.6.6. Table 10 summarizes the VIGP's capital costs.

Capital Cost Item	**Amount**
Site Work & Infrastructure	$ 11.2
Major Equipment[77]	131.2
Building and Building Services	23.8
Piping and Painting	28.9
Electrical and Controls	21.6
Switchyard	5.5
Transmission Interconnect	6.3
Labour Allowance	16.3
Temporary Construction Facilities	2.5
Construction Insurance	1.4
Vendor Supervision[78]	2.6
Engineering and Construction Management	12.5
Project Management and Regulatory	5.9
Operational Commissioning, Testing and Training	13.6
Total Direct	**$ 283.3**
Overhead	5.9
Interest During Construction	38.7
Contingency	12.1
Total	**$ 340.0**

Table 10: VIGP Expected Capital Costs ($ Millions)

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[77] Includes committed amounts for gas and steam turbines (see Table 1); and estimates for items such as heat recovery steam generator, cooling tower, condenser and other ancillary equipment.

[78] On all equipment except gas turbine and steam turbine.

7 Public Consultation

The consultation program for the VIGP began in the fall of 2001 and has continued to date. This section summarizes the consultation program. The activities undertaken from October 2001 to mid-June 2002 are described in greater detail in Section 18 and Appendices B, C and D of VIEC's application for a project approval certificate, now called an environmental assessment certificate (the EAO Application).

7.1 *Consultation Program Overview*

VIEC designed and implemented a broad based consultation program to ensure that interested parties had numerous opportunities to learn about the VIGP and provide input to the proponent. This facilitated the identification of issues and helped to ensure that the input was considered in the planning of the VIGP.

Consultation initially focused on discussions with government officials and community leaders. Direct contact with the public began at the open houses held in February 2002 in Nanaimo, Cedar and Gabriola Island.

One of the key objectives of the VIGP consultation program was to identify and address project-specific issues. However, many of the questions and comments received were related to issues other than the VIGP. BC Hydro prepared responses to those issues as part of its ongoing public education program. VIEC, as the project proponent, worked to address the project-specific issues. The efforts in this area are described in the EAO Application and Final Consultation report. The project-specific issues raised most often were air quality, health, and greenhouse gas emissions. Early in the study process there were also questions about the proposed partnership with Calpine. Numerous other issues were raised and, along with those raised most frequently, are discussed in the EAO Application, Final Consultation Report and Compilation of Responses to Project Related Questions Raised during the Public Comment Period.

All project consultants contributed to the consultation program to help ensure that issues identified in the technical studies were addressed. It was also recognized that the concerns relevant to any particular stakeholder group could change as studies progressed. Therefore, an analysis of the concerns and issues raised was undertaken on an ongoing basis with a view to identifying implications to the technical and community impact assessment work underway as well as potential improvements to the consultation process.

VIEC continues to consult with interested parties and, should the project be approved, will continue to consult through the construction and operations stages of the project. This will help to ensure that the commitments made are realized, that the positive effects of the project are enhanced, and that any negative effects are mitigated.

The specific activities in the VIGP consultation program are summarized below. As noted above, more detailed descriptions of the activities are contained in Section 18 and Appendices B, C and D of the EAO Application and in the Final Consultation Report and

Appendix. Since October 2002, activities have focused on responding to questions from the EAO Project and Technical Committees and from stakeholders.

7.2 *First Nations Consultation*

The VIGP power plant, natural gas service line and power transmission line upgrades lie within the core territory of the Snuneymuxw First Nation (SFN—formerly known as the Nanaimo Band). VIEC has pursued a separate consultation program to provide information to the SFN and to address its members' concerns and issues. The SFN, with a population of approximately 1,350, has six reserves in a 10 km radius of the project site. The transmission lines would cross two of them. Discussions with the SFN regarding the VIGP started in January 2002. Neighbouring First Nations to the north and south of the project have also been notified, either in person or in writing, of consultation activities and have to date raised no issues.

VIEC recognizes that the success of the consultation program depends on ensuring that consultation is undertaken in a manner that is meaningful and appropriate for the SFN. Therefore, VIEC indicated early in the process the importance of the First Nation instructing the proponent as to how best to consult both at official and community levels. Since January 2002, discussions have been underway with the SFN about developing a consultation program for the VIGP.

In June 2002, the EAO informed the SFN that it had accepted the EAO Application for review and invited the SFN chief and council to sit on the EAO Project Committee or, alternatively, nominate a First Nations member to become a reviewing participant in the project's review.[79] The SFN participated in the environmental assessment as a member of the Project Committee. VIEC and the SFN have also signed a capacity funding agreement with the following components:

- funding of professional experts in the fields of health, air quality, water, law and environmental issues for the band to review the project application and be advised of any gaps and/ or concerns related to their interests;
- funding for two community meetings to be held with the proponent and its experts;
- funding for chief and council meetings with the proponent and the community to discuss and address, where required, project impacts; and
- administrative support for the band as it considers the impacts of the project and participates in the review process.

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[79] Letter of Daphne Stancil, Project Committee Chair, to Chief John Wesley, Snuneymuxw First Nation, dated June 5, 2002 at *http://srmapps.gov.bc.ca/epic/output/html/deploy/epic_project_home_195.html*.

Although a number of consultation activities have since taken place, VIEC is now waiting for further guidance from the SFN regarding the means through which its members want to work together to resolve issues and provide information to the SFN community.

8 Cost of Service/Rate Impacts

This section discusses the VIGP's cost of service for the three system portfolios. The analysis was based on a number of assumptions on capital costs, operating, maintenance and administration (OMA) costs, gas commodity costs, and transportation costs. The following are the most crucial assumptions:

- ☐ Calculations are based on BC Hydro fiscal years (ending March 31).[80] Fiscal years 2007 and 2032 are partial years.
- ☐ The VIGP's capital costs are estimated at $340 million (2002 dollars).
- ☐ Capital costs of the project are 100% debt-financed and amortized over 25 years using a cost of debt of 6.00%.
- ☐ Inflation is assumed to be 2% per year.
- ☐ The VIGP plant is assumed to generate 2,100 GWh per year, based on dependable capacity of 265 MW (i.e., not including its 30 MW of duct firing capacity). The plant's heat rate net of degradation is estimated at 7,308 GJ/GWh.
- ☐ OMA costs for the VIGP are estimated at $17.8 million (annualized) in the first year of operation (2006) and assumed to escalate at the inflation rate thereafter.[81] These costs include major maintenance expenditures scheduled in six-year cycles to maximize the plant's life.
- ☐ Gas commodity prices are the same as those discussed in section 5.6.4, plus provincial motor fuel tax of 7.00%.
- ☐ Gas transportation costs from Sumas to the VIGP are based on projected revenue requirements of the GSX Project (a constant $53.0 million), with half of that revenue requirement being attributable to the VIGP.
- ☐ The VIGP's in-service date is assumed to be July 1, 2006. However, for 2006/07, gas transportation costs reflect the assumption that the VIGP's operations will recover costs associated with the GSX Project between October 2005 (expected in service date of the pipeline) and July 2006.

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[80] Adjustments are made for partial fiscal years, such as 2006/07 (reflecting the fact that the VIGP comes in service part way through the fiscal year).

[81] Includes cost of GHG offsets based on voluntary commitments by BC Hydro. See section 3.4

8.1 *Cost of Service*

Applying these assumptions leads to the estimated cost of service for the VIGP, summarized in 5-year increments in Table 11.

	2006/07	2007/08	2010/011	2015/16	2020/21	2025/26	2030/31	2031/32
OMA	13	18	18	20	22	25	27	7
Gas Commodity	60	82	87	96	106	117	129	32
Gas Transportation	41	27	27	27	27	27	27	7
Motor Fuel Tax	4	6	6	7	7	8	9	2
Capital Charge	21	28	28	28	28	28	28	7
Total Cost of Service (Nominal Dollars)	**139**	**161**	**166**	**177**	**189**	**204**	**219**	**55**
Total Cost of Service (2002 Dollars)	**108**	**143**	**139**	**135**	**131**	**127**	**124**	**31**
Annual Energy (GWh)	1,575	2,100	2,100	2,100	2,100	2,100	2,100	525
Cost Per MWh (Nominal Dollars)	**89**	**76**	**79**	**84**	**90**	**97**	**105**	**105**
Cost Per MWh (2002 Dollars)	**68**	**68**	**66**	**64**	**62**	**61**	**59**	**59**

Table 11: Cost of Service for the VIGP 2006/07 - 2031/32 ($ Millions)

8.2 *Rate Impacts*

BC Hydro is preparing an application to the BCUC in the context of an inquiry[82] into BC Hydro's Heritage Resources. That application will set out BC Hydro's position on the value of its existing low-cost generation assets. BC Hydro requires that analysis to forecast the rate impact of the VIGP. Accordingly, VIEC intends to file the rate impact analysis with the Commission when BC Hydro makes its Heritage Resource application, expected to be in April 2003. VIEC considered it prudent to file this CPCN application now and to provide the rate impact analysis later, in view of the time constraints in meeting the VIGP's target in-service date.

The possible rate increases discussed in the BC Hydro Service Plan of February 2003 also need to be incorporated into the portfolio results in chapter 5, in order to analyze rate sensitivity and to estimate the rate impacts of the portfolios. As noted in subsection 4.1.2, the portfolio analysis for this application was prepared before the Service Plan had been released. Accordingly, the rate increases proposed in that plan have not been considered in this application. The appropriate analysis will be filed with the Commission when it is completed.

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[82] Pursuant to section 5 of the *Utilities Commission Act.*

9 Other Applications and Approvals

A variety of other approvals or permits are required and being sought from various federal, provincial and municipal authorities. This section discusses the significant additional processes and includes a summary of all approval processes.

9.1 *Georgia Strait Crossing (GSX) Project Approvals*

The VIGP requires gas transportation service from the proposed Georgia Strait Crossing Project (the GSX Project), which involves the design, construction and operation of a new natural gas pipeline from the market hub at Sumas, Washington to Vancouver Island, British Columbia. The pipeline will permit natural gas purchased at Sumas to be transported to markets in northwestern Washington state and to Vancouver Island.

9.1.1 Canadian Approvals

The Canadian portion of the GSX Project (the GSX Canada Pipeline) is subject to federal regulatory approval. In April 2001, Georgia Strait Crossing Pipeline Limited (GSX PL), a proponent of the GSX Project and a wholly-owned subsidiary of BC Hydro incorporated under the laws of Canada, applied to the National Energy Board (NEB) for a CPCN and related orders respecting the Canadian portion of the GSX Canada Pipeline. GSX PL will construct and operate the GSX Canada Pipeline. Its application was presented to the NEB in five volumes and is available for viewing, along with related filings, at *http://www.gsxreg.com* and at *https://www.neb-one.gc.ca/index_e.htm.*

The NEB process has two stages. First, the NEB decides whether the project is in the public interest, taking into account environmental effects, economic feasibility, socio-economic and land matters, engineering and safety concerns, adequacy of consultation with First Nations, and tolling and tariff issues. Then the NEB determines the detailed route of the pipeline, after considering any objections by landowners from whom land or rights of way are required.

In addition to requiring NEB approval, the GSX Canada Pipeline is subject to review by the Canadian Environmental Assessment Agency (CEAA). In September 2001, the Chair of the NEB and the federal Minister of the Environment established a Joint Review Panel (JRP), to represent both agencies, to review the GSX Canada Pipeline. The JRP public hearing commenced on February 24, 2003.

9.1.2 US Approvals

The portion of the GSX Project located in the United States (the GSX US Pipeline) will be constructed and operated by Georgia Strait Crossing Pipeline LP, a limited partnership formed under the laws of Utah. The limited partners of Georgia Strait Crossing Pipeline LP are GSX Western Pipeline Company, a wholly-owned subsidiary of Williams

Gas Pipeline Company, LLC[83] and GSX Pipeline (US) Corp., a wholly-owned subsidiary of BC Hydro. In April 2001, Georgia Strait Crossing Pipeline LP applied to the Federal Energy Regulatory Commission (FERC) for a CPCN and other authorizations for the GSX US Pipeline. The application and related filings are on the FERC website.[84]

The FERC process has two basic stages. The FERC may first issue a preliminary determination on whether a project is in the public interest based on its evaluation of non-environmental issues, such as rates and project need. After assessing the environmental issues, the FERC may then issue a final order approving the project and establishing appropriate environmental mitigation conditions.

On March 13, 2002, the FERC issued a preliminary determination on non-environmental issues relating to the GSX US Pipeline, concluding that the public interest would be served by issuing the requested authorizations, subject to favourable environmental assessment.[85] On September 20, 2002, the FERC issued its final order authorizing construction and operation of the project.[86] The FERC concluded that the pipeline is required by public convenience and necessity and that it will have limited environmental impact if constructed and operated in accordance with the pipeline application and certain stipulated mitigation measures. The FERC order makes commencement of construction conditional on the NEB first approving the GSX Canada Pipeline.

In November 2002, two intervenors asked the FERC for a rehearing based on various environmental and safety considerations. The FERC denied the requests for rehearing on January 17, 2003 and issued the relevant certificates and permits.[87]

9.2 *Provincial or Other Approvals*

9.2.1 Environmental Assessment Office (EAO) Application

In June 2002, VIEC applied to the British Columbia Environmental Assessment Office (EAO) for a project approval certificate to build the VIGP. The application is on the EAO website[88] and at the EAO Project Information Centre in Victoria. It includes an integrated assessment of the project's environmental, social, economic, health, cultural and First Nations impacts.

The EAO process is intended to identify potential adverse impacts through a project's life cycle—including construction, start-up, operation and shut-down—and to assess ways to eliminate or mitigate those impacts. The EAO is responsible for seeing that project reviews are comprehensive and technically sound, involve all potentially interested parties, and are conducted in an open and efficient manner.

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[83] In turn a wholly-owned subsidiary of The Williams Companies, Inc.

[84] At *www.ferc.gov/index.htm*. See dockets CP01-176 *et al.*

[85] 98 FERC 61,271.

[86] 100 FERC 61,280.

[87] 102 FERC 61,051.

[88] At *http://srmapps.gov.bc.ca/epic/output/html/deploy/epic_project_home_195.html.*

At the time of filing the application, the EAO process had up to three stages. An application was first placed on the Project Registry and the EAO established a Project Committee to review it. Following a public comment period, the Committee was to review the application and could recommend either granting or refusing a certificate. The recommendations would be considered by the Minister of Sustainable Resource Management and a second appropriate minister for a decision. Alternatively, the Committee could request a detailed Project Report from the applicant, again filed with the Project Registry for a period of public comment. The outcome of that process was a recommendation to the two ministers to approve project certification, deny certification, or refer the project to the Environmental Assessment Board for a hearing. Following such a hearing, the Board would submit its report and recommendations to Cabinet, which then would decide whether to issue a project approval certificate.

The public comment period on the VIGP application ended in October 2002, having been extended from two months to three months in duration. On December 30, 2002, new environmental legislation came into force. Transition orders were issued for projects already in the process. By an order dated December 30, 2002, the EAO ordered that an environmental assessment certificate, as it is called under the new *Environmental Assessment Act*, will be required for the VIGP, and that the EAO Application and supporting information provided by VIEC to date will be accepted as an application under the new process.[89]

On February 5, 2003, the VIGP Project Assessment Director, acting pursuant to certain delegated powers under the new legislation, issued a detailed order setting out the scope, procedures and methods to be followed in completing the project's environmental assessment. This order (the EAO Scoping Order) is attached at Appendix D. Among other things, it provides for the views of former Project Committee members to be included in the assessment report, and stipulates that the application and the assessment report will be referred to the relevant Ministers for a decision by April 17, 2003. The Ministers then have 45 days to make a decision,[90] which means that VIEC expects a decision on the environmental assessment certificate by June 2, 2003.[91]

9.2.2 Other Approvals

Table 12 summarizes VIEC's best understanding of the additional approvals that are required for the VIGP to be feasible, along with the respective regulatory authority.

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[89] Transition Order 02-17 at *http://srmapps.gov.bc.ca/epic/output/html/deploy/epic_document_195_14650.html*

[90] *Prescribed Time Limits Regulation*, B.C. Reg. 372/2002, s. 4.

[91] The 45-day time limit may be extended by order of the Minister or Executive Director: see *Environmental Assessment Act*, SBC 2002, c. 43, s. 24(4).

Authority*	Description	Summary
MCAWS	Contractor Licenses for Boilers, Pressure Vessels and Piping	*Canadian Power Engineers and Boiler and Pressure Vessel Safety Act* requirement
MCAWS	Electrical Contractor License	*Electrical Safety Act* requirement
MCAWS	Electrical Maintenance Permit	Annual permit for maintenance and alteration of installed electric equipment, *per Electrical Safety Act*
MCAWS	Electrical Permit	Permit and notification provided to inspection authority, handled by Electrical Safety Branch
MCAWS	Gas Installation Permit	*Gas Safety Act* requirement
MCAWS	Gas Installer License	*Gas Safety Act* requirement
MCAWS	Plumbing Contractor License	*Canadian Power Engineers and Boiler and Pressure Vessel Safety Act* requirement
MCAWS	Power Plant Operator Certificate	*Canadian Power Engineers and Boiler Pressure Vessel Safety Act* requirement
MCAWS	Storage and Dispensing of Fuels Permit	Safety and Standards Department, Office of the Fire Commissioner, Local Assistant Fire Commissioner *per Fire Services Act*
MHS	Mobile Caterer Permit	*Health Act* requirement
MHS	Potable Water Permit	Design approval/permit for temporary water works for construction staff; same for permanent water works
MOF	BC *Forest Practices Code* Approvals	Approval for clearing ROWs and preparedness for forest fire prevention and suppression
MOT	Oversize/Overweight Load Permit	*Commercial Transport Act* requirement
MSR	Archaeological Permit	*Heritage Conservation Act* requirement
MSR	Water Licence or Transfer of Appurtenancy	water supply
MWLAP	Air Emission Permit	air emissions under *Waste Management Act*
MWLAP	Liquid Effluent Discharge Permits during construction	discharge of storm run-off from settling pond; may need to amend existing permit for VIGP effluent
NC	Building Permits	plant construction
OGC	Approval for gas transportation facilities	pipeline construction—required by *Pipeline Act*

Table 12: Other Required Applications and Approvals

*Acronyms for Relevant Authorities:

MCAWS	Ministry of Community, Aboriginal and Women's Services
MCF	Ministry of Forests
MHS	Ministry of Health Services
MOT	Ministry of Transportation
MSR	Ministry of Sustainable Resources
MWLAP	Ministry of Water, Land and Air Protection
NC	City of Nanaimo
OGC	Oil and Gas Commission

10 Conclusions

Over the long-term, the expected retirement of existing Vancouver Island HVDC transmission capacity, coupled with the growing demand for electricity on the Island, requires additional supply resources to ensure reliable electricity service to Vancouver Island customers.

Alternative 20-year resource portfolios were developed to assess various resource options that could cost effectively meet Vancouver Island's reliability requirements while meeting the long-term planning objectives for the BC Hydro system as a whole. Based on the analysis in this application and on other planning considerations, development and construction of the VIGP is the prudent and appropriate course of action.

Table 13 demonstrates how the VIGP meets BC Government energy policy and BC Hydro's electricity planning objectives.

BC Government Energy Policy	BC Hydro Electricity Planning Objectives	Applying the Objectives to the VIGP
Low electricity rates and public ownership of BC Hydro.	Minimize economic costs by establishing the least cost sequence of resources that meet customers' needs and other policy objectives.	The VIGP is one of the least cost alternatives to Vancouver Island's capacity needs, and does so with the greatest construction cost certainty. With GSX, the VIGP creates significant economic option value for pursuing future Island generation.
Secure, reliable supply.	Maintain adequate capacity and energy to meet customer needs by ensuring that industry reliability criteria are met.	The VIGP reduces the risk of inadequate reliable electrical capacity for Vancouver Island sooner than the alternatives and with the greatest timing certainty. Reliability is of particular concern given the expected retirement of the HVDC system. The VIGP provides additional system planning benefits related to energy supply diversification and future planning flexibility.
More private sector opportunities.	Encourage the private sector to provide proposals to supply power to BC Hydro.	There will be private sector involvement in the design, construction and operation of the VIGP whether the project is sold to an IPP, as is expected, or operated for VIEC under contract.
Environmental responsibility and no nuclear power sources.	Enhance environmental responsibility through conservation and a 50% clean energy target through Power Smart, Customer Based Generation, Green Energy and Resource Smart Programs and by proposing projects that meet or exceed environmental and social requirements.	The VIGP will be one of the cleanest natural gas-fired generation facilities in North America, and its 2006 in-service date will facilitate the consideration and development of Power Smart, Customer Based Generation, Green Energy and Resource Smart Programs to supply dependable capacity to Vancouver Island.

Table 13: Application of Policy & Planning Objectives to VIGP

Appendix A: Glossary

This Appendix lists defined terms, acronyms and metric units used in the application.[92]

Absolute Pressure	See Pa and kPa
A	See **Ampere**.
AC	See **Alternating Current**.
Alternating Current (AC)	Electric current that reverses at regular intervals and has alternately positive and negative values. It normally has a sinusoidal shape with a standard **frequency** of 50 or 60 **Hertz** (**Hz**) or cycles per second. Most of the power transmission in North America is AC transmission, and carries three-phase, 60 Hz power. In three–phase transmission, three conductors or phases are used ; the currents and voltages of each phase are displaced in time symmetrically from those of the other phases.
Alternative Technologies	Non-conventional electricity generating methods involving fuel cells, tidal, solar, wind and wave energy sources.
Ampere (A)	Basic unit of measurement for the intensity of an electric current.
Ancillary Services	Services required to support transmission of capacity and energy from resources to loads and to maintain reliability.
Apparent Power	Voltage multiplied by current, normally measured as **MVA**, megavolt amperes.
Arnott	Mainland terminal of the Vancouver Island HVDC Transmission System, near Ladner.
Asynchronous Tie	A transmission connection between two power systems allowing each of the AC systems to run at independent frequencies.
Atmospheric Pressure	101.325 kPa = 1 standard atmosphere
British Thermal Unit	Imperial unit for heat energy (1 Btu = 1,054.6 J)
Btu	See **British Thermal Unit**.

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[92] Sources include: *1992 Electricity Plan* (BC Hydro); *1994 Electricity Plan* (BC Hydro); *1994 Cost of New Electricity Supply in BC* (BC Hydro); *1995 Integrated Electricity Plan* (BC Hydro); *Making the Connection* (BC Hydro: 2002); *Vancouver Island Generation Project: Application for Project Approval Certificate* (Vancouver Island Energy Corporation: 2002); *North American Electric Reliability Council Glossary of Terms* (NERC Glossary of Terms Task Force: August 1996); *Energy Information Administration Glossary of Electricity Terms* (US Department of Energy: September 2002); *Energy for Our Future: A Plan for BC* (Government of British Columbia, Ministry of Energy and Mines: November 2002); BC Hydro Info website (http://www.bchydro.com/info/); Environmental Assessment Office website (http://www.eao.gov.bc.ca); *BC Hydro Greenhouse Gas Report* (BC Hydro: June 2001); IEEE Standard Dictionary of Electrical and Electronics Terms; IEEE Red Book; EPRI Transmission Services Costing Framework.

Bulk Transmission	This is the "backbone" or major high voltage transmission system that carries the majority of the power from the generators to the lower voltage regional systems and carries the interchanges with USA and Alberta.
Canadian Entitlement	The Canadian portion of the **Columbia River Treaty** downstream energy and capacity benefits (DSBs) resulting from increased electricity generation on the Columbia River in the US due to the construction of Duncan, Keenleyside and Mica storage dams. The return of the DSBs to which Canada is entitled commencing April 1, 1998 and ending September 15, 2024, are to be delivered over existing interties with the US.
Capability	The quality of being able to be developed or used, which, in relation to the integrated system, refers to facilities that can be used under specified conditions for a given period of time. *Energy capability* is the amount of energy that can be generated under specified conditions by a generator or by the electric system over a period of time, typically expressed in GWh/year.
Capacity	The rated power output, normally measured in kilowatts (kW) or megawatts (MW), of a power plant, or transmission facility's ability to transmit electricity, at any instant. Several related terms are commonly used: *Maximum:* The highest generator output or transmission loading that can be achieved. *Nameplate:* The maximum rating of a generator or transmission station equipment identified by the manufacturer under specified conditions. *Dependable:* (Also referred to as *firm*). The maximum generator output or transmission power transfer that can be reliably supplied coincident with the system peak load, taking into account the physical state and availability of the equipment, and on water or fuel constraints. See also **Demand**.
Capacity Factor	The ratio of the average annual power output to the rated power output of generating plants.
CBG	See **Customer-Based Generation**.
CCGT	See Combined Cycle Gas Turbine
CEAA	Canadian Environmental Assessment Agency. Together with the NEB, constitutes the **Joint Review Panel** (**JRP**) charged with reviewing the **GSX Canada Pipeline**.

Centra	Centra Gas Inc., a distribution utility that delivers natural gas to residential and commercial customers and seven pulp mills on Vancouver Island. Centra's pipeline begins in Coquitlam BC, crosses the Georgia Strait from Powell River to the Courtenay-Comox area on the Island, and runs north from there to Campbell River and south to Victoria.
Cheekye	BC Hydro 500 kV transmission station near Squamish; effective Mainland terminal for the 500 kV AC interconnection to Vancouver Island.
CIEEDAC	Canadian Industrial Energy End-Use Data and Analysis Center.
Circuit	Generally refers to specific three-phase **AC** transmission lines, submarine and underground cables, or a combination of these, operating as one element.
Clean Energy	Refers to November 2002 policy decision by provincial government, requiring electricity distributors to pursue a voluntary goal to acquire 50% of new supply over the next ten years from sources that result in a net environmental improvement relative to existing energy production. Examples include small/micro hydro, wind, solar, photovoltaic, geothermal, tidal, wave and biomass energy, as well as cogeneration of heat and power, energy from landfill gas and municipal solid waste, fuel cells, and efficiency improvements at existing facilities.
CO	Carbon monoxide.
CO_2	Carbon dioxide.
CO_2e	Carbon dioxide-equivalent. A unit that measures the climate change potential of each of the six **greenhouse gases** identified in the **Kyoto Protocol**.
Cogeneration	The production of electricity and useful heat from a single energy source.
Columbia River Treaty	A treaty between Canada and the US that enabled storage reservoirs to be built and operated in British Columbia to regulate Columbia River flows to the US, for shared power benefits and flood control. See also **Canadian Entitlement**.
Combined Cycle Gas Turbine (CCGT)	The combination of combustion and steam turbines to generate electricity from two thermodynamic cycles. The exhaust gases from the combustion turbine are directed to a heat recovery steam generator (HRSG) that produces steam to power a steam turbine. The result is a higher **thermal efficiency** than achievable by operating the combustion or steam turbines individually.
Conservation	A reduction in energy consumption without a reduction in service, achieved by changes in consumer behaviour such as turning off unnecessary lights or by improving end-use technology such as more efficient lights. See also **Demand Side Management**.

Converter	Equipment that converts AC power to DC power (rectifier- mode) and DC power to AC power (inverter-mode).
CPCN	Certificate of Public Convenience and Necessity.
Critical Period	A period of record low **streamflows**. Critical water conditions serve as a design test of the capability of a hydroelectric system to meet the load forecast under adverse reservoir inflows. During a critical period, hydroelectric reservoirs would be drawn down to minimum levels in order to sustain service. See also **Secondary Energy**.
CTG	Combustion Turbine Generator. See also **Turbine Generator**.
Current	Flow of electricity passing through a conductor, measured in amperes (A). Current can be alternating (AC) or unidirectional (DC).
Customer-Based Generation (CBG)	BC Hydro resource acquisition initiative to buy electricity from its larger customers through a competitive acquisition process.
DC	See **Direct Current**.
Decommission	Take an asset permanently out of service.
Demand	The rate at which electric energy is delivered to or by a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated time interval. Several related terms are commonly used:

Instantaneous Demand:	Rate of energy delivered at a given instant.
Average Demand:	The electric energy delivered over any interval as determined by dividing the total energy by the units of time in the interval.
Demand Interval:	The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.
Peak Demand:	The highest electric requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.
Coincident Demand:	The sum of two or more demands that occur in the same demand interval.

See also **Capacity**.

Demand-Side Management (DSM)	Actions that modify customer demand for electricity, helping to defer the addition of supply-side energy or capacity.

Derating	Embodies the notion that equipment can only operate at a rating less than its original design rating because of a deficiency or physical condition. The derating can be temporary or permanent.
Developed Rivers	Rivers whose flows have been harnessed for the generation of hydroelectric power.
Direct Current (DC)	Unidirectional current in which the changes in value are zero. As ordinarily used, the term designates a practically non-pulsating current, as with a battery. DC transmission, frequently referred to as high voltage direct current (HVDC), is used in specialized applications. See also **AC**.
Discount Rate	The rate used to determine the **present value** of expenses and revenues occurring over a period of time. It represents the time value of money.
Dispatchable	Term that can be applied to supply- or demand-side resources. A resource that is fully dispatchable by BC Hydro is one that can be adjusted to address variations in short term load/resource balance associated with weather changes, unit outages, variations in the market price of electricity, and non-power considerations.
Distillate	Generally, one of the petroleum fractions produced in the distillation of crude oil. It is used primarily for space heating, diesel engine fuel, and electric power generation.
Distribution System	Electrical lines, cables, transformers and switches used to distribute electricity over short distances from substations to the customer. The distribution system voltage is generally less than 60 kV.
Duct Firing	Combustion of fuel in burners located in ducting at the inlet to a heat recovery steam generator to supplement the heat input to the boiler from hot exhaust gases from a gas turbine or other heat source.
Duke Point	The name given to the industrial area within the City of Nanaimo, centred about 5 km southeast of the downtown area, which includes Duke Point.
Dunsmuir	BC hydro 500 kV transmission station; near Qualicum Bay; Vancouver Island terminal of the 500 kV AC interconnection.
EAO	See **Environmental Assessment Office**.
EDUCOGEN	European Education Tool on Cogeneration.
Efficiency	The effective rate of conversion of a natural resource (e.g., natural gas) to useable energy and capacity or the effective rate of conversion of electricity to an end use (e.g., heating).
Electric Generation Efficiency	The ratio between a power plant's electric output and the lower heating value (LHV) of the heat input, expressed as a percentage.

Electricity Demand	See **Demand**.
Electricity Intensity	The electrical energy consumed per application or end-use, such as kWh/m^2 of lit office space per day
Electro-mechanical Stability	The condition of operation of an AC electrical system based on all generators operating in synchronism; that is, at the same frequency and in-phase with each other and able to withstand normal disturbances that could otherwise cause instability. The instability can occur within a fraction of a second or minutes. It can result in the electrical breakup of the transmission system into several sections and a widespread interruption of the electrical load or blackouts. See also **Transient Stability**.
Energy	The amount of electricity produced or used over a period of time, usually measured in kWh or GWh.
Energy Capability	The assured amount of energy that a generating plant can produce in a given time period (usually one year).
Energy Purchase Agreement (EPA)	The contract that defines the terms and conditions by which BC Hydro purchases electricity from **independent power producers**.
Environmental Assessment Certificate	An approval certificate issued by the relevant Ministers pursuant to the BC *Environmental Assessment Act*.
Environmental Assessment Office (EAO)	A provincial agency that coordinates assessment of the impacts of major development proposals in BC and reports to Minister of Sustainable Resource Management.
EPA	See **Energy Purchase Agreement**.
FERC	Federal Energy Regulatory Commission. US regulator responsible for approving construction of the **GSX US Pipeline**.
Firm Energy	The assured energy contribution of the electric system over a period of time, typically one year.
Firm Export	The assured sale of a contracted amount of energy and/or capacity to utilities or customers located outside the boundaries of BC Hydro's service area.
Firm Gas	The assured supply of natural gas as fuel for thermal generating stations.
Firm Gas Contract	An assured contract to supply or purchase a specified volume of gas at a fixed price.
Firm Transmission	Transmission service that is reserved and/or scheduled with a priority that will not be interrupted for economic reasons.
Flow Release	The release of water through a hydroelectric facility at a prescribed flow rate.

Frequency	The standard frequency of **AC** transmission systems in North America is 60 cycles per second, or 60 **Hertz** (**Hz**). Maintaining proper regulation and control of system frequency through the planning and operation of generators and remedial action schemes is an important goal of system design, apart from considerations of energy supply.
Gas Commodity Costs	The price of natural gas purchased from the gas market.
Gas Transportation Costs	The amount paid to the owner of a pipeline for gas delivery service through that pipeline.
Gauge Or Excess Pressure	Pressure in excess of 1 atmosphere (see atmospheric pressure).
Generation	The production of electricity.
Generator	A machine that converts mechanical energy into electric energy.
GHG	See **Greenhouse Gases**.
GHG Offset	Reducing total emissions of greenhouse gases by decreasing emissions from other sources rather than the source in question. For example, reducing methane emissions from landfill sites can be an offset for a thermal generation plant.
Gigajoule (GJ)	1 billion joules of energy.
Gigawatt-Hour (GWh)	One million kilowatt-hours—an amount of electric energy that will serve about 100 residential customers for one year.
GJ	Gigajoule (10^9 Joules)
GJ/h	Gigajoule per hour (1.055 GJ/h = 1 million Btu/h)
Green Energy	Energy produced from a green power project. BC Hydro's requires such projects to be renewable, environmentally and socially responsible, and licensable.
Greenhouse Gases (GHG)	Gases that are thought to contribute to global climate change, or "greenhouse effect." These include carbon dioxide (CO_2), carbon monoxide (CO) and methane (CH_4).
Grid	Network of transmission lines.
GSX Canada Pipeline	The Canadian portion of the **GSX Project**.
GSX Project	Georgia Strait Crossing Project. Involves the design, construction and operation of a proposed natural gas pipeline from the Sumas Hub in Washington State to Vancouver Island.
GSX US Pipeline	The US portion of the **GSX Project**.
H_2O	Water.
H_2S	Hydrogen sulphide.

H_2SO_4	Sulphuric acid.
Harmac Site	Name given to the preferred site of the proposed **VIGP**, located on property acquired by **VIEC** from Pope & Talbot Ltd.
Head	The vertical distance between the water levels immediately upstream and downstream of a turbine or discharge structure. The head represents the potential energy of the water which can be used to generate electricity as the water falls to the lower elevation.
Heat Rate	A measure of generating station **thermal efficiency**, computed by dividing the heat content of the fuel used for generating electricity by the resulting net electric energy generated. Typically expressed in GJ/GWh or kJ/kWh.
Henry Hub	One of the major pipeline hubs of the North American natural gas market; located in Louisiana. Used as a reference point for quoting the market price of gas.
Hertz (Hz)	Unit for measuring the **frequency** of an **AC** system.
HHV	Higher heating value of a fuel, with **LHV** being the lower value. Heating value is a measure of the energy released when a fuel is burned, and is the basis for calculating the energy efficiency of a thermal process. HHV includes the heat released when water produced by combustion of the fuel's hydrogen condenses. LHV excludes the heat released by condensing water, assuming it stays in vapour form. For natural gas, LHV is about 90% of HHV.
High Voltage Direct Current (HVDC)	Direct (non-alternating) current for transmission at high voltages. See also **Direct Current**.
HNO_3	Nitric acid.
HP	High pressure.
HP	Mechanical shaft horsepower.
HRSG	Heat recovery steam generator.
HVDC	See **High Voltage Direct Current**.
Hydroelectric Generation	Production of electricity through the use of turbines to extract energy from falling water or **streamflow**.
Hz	1 cycle per second (see frequency)
ICEC	See ICP
ICP	Island Cogeneration Project (also called Island Cogeneration Energy Center).
IEP Update	2000 Update to BC Hydro's 1995 **Integrated Electricity Plan**.
Independent Power Producer (IPP)	An entity that produces electricity for market to utilities or other customers.

Inflow	Water that flows into a reservoir.
Integrated Electricity Plan (IEP)	The documented Plan resulting from the Integrated Resource Planning Process.
Integrated Resource Planning (IRP)	A planning process which involves stakeholders in evaluating a wide range of supply-side and demand-side options to determine the most appropriate mix of resources to reliably meet future electricity requirements.
Integrated System	The interconnected network of transmission lines, distribution lines and substations linking generating stations to one another and to customers throughout the BC Hydro electric system.
Interruptible Energy	A supply of electricity that is subject to short- or long-term discontinuation with or without notice.
IPP	See **Independent Power Producer**.
IPP Review Panel	The government appointed panel that ranked the short-listed **IPP** proposals from BC Hydro's 1994 Request for Proposals on the basis of their social costs.
Joule (J)	Metric unit for heat energy ($1 \text{ J} = 9.4821 \times 10^{-4}$ Btu).
JRP	Joint Review Panel. See **CEAA** and **NEB**.
Kilovolt (kV)	One thousand volts.
Kilowatt (kW)	One thousand watts; the commercial unit of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.
Km	Kilometre.
KPa	1000 pascals.
kV	Kilovolt (1000 volts).
KVA	Kilovolt ampere. The measure of **apparent power**. It is equal to 1000 volt amperes.
KVAR	Kilovolt ampere reactive. It is a unit of **reactive power**.
KW	Kilowatt (1000 watts).
Kyoto Protocol	The United Nations Framework Convention on Climate Change. The Protocol, which still requires ratification by other countries, seeks to reduce overall emissions of greenhouse gases such as CO_2 (carbon dioxide), CH_4 (methane), and N_2O (nitrous oxide) by at least 5% below 1990 levels in the commitment period of 2008 to 2012.
Levelized Cost/Price	Levelizing is a method of converting a non-uniform stream of energy costs (or prices) into a present value-equivalent uniform cost (or price) series.
LHV	Lower heating value of a fuel (see **HHV**).

Live Storage	Storage that can be released from a reservoir.
Load	The amount of electricity required by a customer or group of customers as measured by an electrical metre.
Load Centre	The region where the majority of electricity customers are located.
Load Displacement	The reduction of electricity requirements from existing customers by using electricity more efficiently or by the addition of customer self-generation.
Load Factor	The ratio of the average load supplied during a given period to the maximum load occurring during the same period.
Load Forecast	The expected customer electricity requirements that will have to be met by the electrical system in future years.
Load Forecasting	The determination of an estimate of load requirements for some future time.
Load Profile	The shape of electricity supply or demand over a time period. For example, a one day hourly load profile for a customer shows hourly consumption over a 24-hour period.
Load Shedding	Normally refers to controlled interruption of load when multiple system emergencies or contingencies occur. Can be done either manually by operator action, or by automatic protective relaying such as by the under-voltage load shedding scheme or by under-frequency load shedding scheme.
Losses (Line, Transmission)	Transmission losses refer to loss in power and energy as heat in electrical equipment and along transmission lines due to resistance as electricity is transferred from one location to another. There are also reactive losses associated with the transmission of electricity (see **Reactive Power**).
Loss-Of-Load Probability Criterion	A probabilistic assessment of the potential for simultaneous outages of generating units. It is obtained by calculating the probability that daily peak demand would exceed available capacity for each day and adding these probabilities for all the days in the year. BC Hydro has applied this criterion by adopting a one-day-in-ten-years allowable risk of load loss.
LP	Low pressure.
LTEPA	Long Term Energy Purchase Agreement under which BC Hydro receives electric energy produced by Alcan.
M	Metre.
m/s	Metres/second.
m^3	Cubic metre.
Malaspina	BC hydro 500 kV transmission substation in the Sechelt Peninsula. It is the terminal station for the **Malaspina-Dunsmuir** 500 kV AC submarine cable circuits. It is connected to **Cheekye** and serves Powell River and Howe Sound Pulp Mill.

Megajoule	One million joules.
Megawatt (MW)	One thousand kilowatts. This term is commonly used to measure both the capacity of generating stations and the rate at which energy can be delivered.
MJ	Megajoule (one million joules).
Mm	Millimetre (0.001 m).
MMBtu	One million British thermal units.
Multiple Account Evaluation (MAE)	A framework developed to facilitate identification and evaluation of financial, customer service, environmental, social and economic development impacts as part of a decision-making process.
MVA	1000 **kVA**.
MVAR	1000 **kVAR**.
MW	Megawatt. One thousand kW.
MWh	Megawatt hour. One thousand kWh.
N-1	A single system contingency event involving the loss of one component.
N_2	Nitrogen.
N-2	A double system contingency event involving the loss of two components.
NEB	National Energy Board. Together with the **CEAA**, constitutes the **Joint Review Panel** (**JRP**) charged with reviewing the **GSX Canada Pipeline**.
NERC	North American Electric Reliability Council
Net Thermal Efficiency	See **Electric Generation Efficiency**.
NH_3	Ammonia (anhydrous)
NH_4NO_3	Ammonium nitrate
Non-Firm Transmission Service	Point-to-point transmission service that is scheduled and paid for on an as available basis and is subject to interruption.
Non-Integrated Areas	BC Hydro service areas which are not connected to the **integrated system**. These areas are supplied by local diesel generation or hydroelectric generation.
Non-Power	Those features of electric system operations that are not related to the production of electricity.
NO_x	Oxides of nitrogen, including NO and NO_2, expressed as NO_2 equivalent.
NPV	Net present value. (See **Present Value**).
Pa	Pascal

PACP	Port Alberni Cogeneration Project. Predecessor to the **VIGP**.
PAGP	Port Alberni Generation Project. Successor to the **PACP** and predecessor to the **VIGP**.
Pascal (Pa)	Metric unit of absolute pressure 1000 Pa = 1 kPa (6.8947 kPa = 1 pound per square foot)
Peak Capacity	The maximum amount of electrical power that generating stations can produce in any instant.
Peak Demand	The maximum instantaneous demand experienced by a power system. Normally the maximum hourly demand.
Phase-shifting Transformer	Also called phase angle regulators, these devices are special kind of transformers that induce a power flow into a circuit, in order to increase or decrease the power loading of that circuit by inserting a voltage phase angle difference.
Point-to-Point Power Flow	The transmission of power from one point to another point.
Pole	In HVDC transmission systems, *pole* refers to one polarity of voltage for DC transmission. For example, in the HVDC system between **Arnott** and **VIT**, the positive voltage transmission is called Pole 1; the negative voltage transmission, Pole 2.
Portfolio	A group of individual resources acquired in a sequence that meets the 20-year Probable Demand Forecast.
Power	The instantaneous rate at which electrical energy is produced, transmitted or consumed, typically measured in watts (W), kilowatts (kW), or megawatts (MW). See also **Capacity**.
Power Factor	The power factor is the ratio of active power (kW) to **apparent power** (kVA) in a circuit. It varies between 0 and 1, and is normally given in percent (0 to 100%).
Power Smart	BC Hydro's program to encourage energy efficiency investments by its customers.
Power Transfer Capability	The power that can be transferred over a particular section of a transmission system in a reliable manner.
Powerhouse	The building or structure containing generators and ancillary equipment.
Present Value (PV)	Today's value of future receipts or expenditures. See also **NPV**.
Probable Demand Forecast	The 20-year Reference Forecast modified to account for changes in demand attributed to expected rate changes (price elasticity of demand).
Probable Load Forecast	The Probable Demand Forecast modified to account for expected savings from demand-side management programs.
Process Steam	Steam used by industry for uses such as heating and chemical processes.

Psig	Pounds per square inch gauge (pressure above **atmospheric pressure**).
Pumped Storage	The use of electricity generated during off-peak hours to pump water from a lower elevation reservoir to a higher reservoir. The stored water is then released during peak demand periods and used to turn a reversible pump/turbine generator before returning to the lower reservoir.
Purchases	The acquisition of electricity from other utilities or independent power producers.
Reactive Compensation	Reactive compensation provides voltage support and control and increases the power transfer capability of the transmission system.
Reactive Power	Reactive power is required to supply the electromagnetic fields of electrical equipment necessary to maintain the flow electrical energy. The energy associated with this component is zero and produces no useful work. The unit of reactive power is the VAR or megaVAR (MVAR). Most load types require some reactive power along with the active power that produces useful work. When the reactive power supply in a transmission system is insufficient, voltages decline to unacceptable levels.
Reference Forecast	The estimated 20-year forecast of electricity demand, excluding effects of demand elasticity and demand-side management programs.
Rehabilitation	Upgrading or restoring the performance of an existing facility.
Reinforcement	Improvements in the electrical system to maintain or increase reliability and security of supply.
Reliability	A measure of the continuity and quality of electric service. Reliability of service to an individual customer depends on the reliability of generation, high-voltage transmission and low-voltage distribution.
Reserve	Additional system generating capacity, beyond that required to meet peak demand, necessary to meet reliability criteria for planning and operation.
Reservoir	The body of water impounded behind a dam.
Resource	A source of electricity that is available to help meet electricity demand. Resources include generation, demand-side management and transmission facilities.
Resource Smart	The name given to BC Hydro's strategy of improvements to existing power generation and transmission facilities to increase power output and efficiency.
Right-Of-Way	The land rights acquired by a utility to allow the construction and operation of electrical transmission or distribution facilities.
River Basin	The geographic area drained by a river.

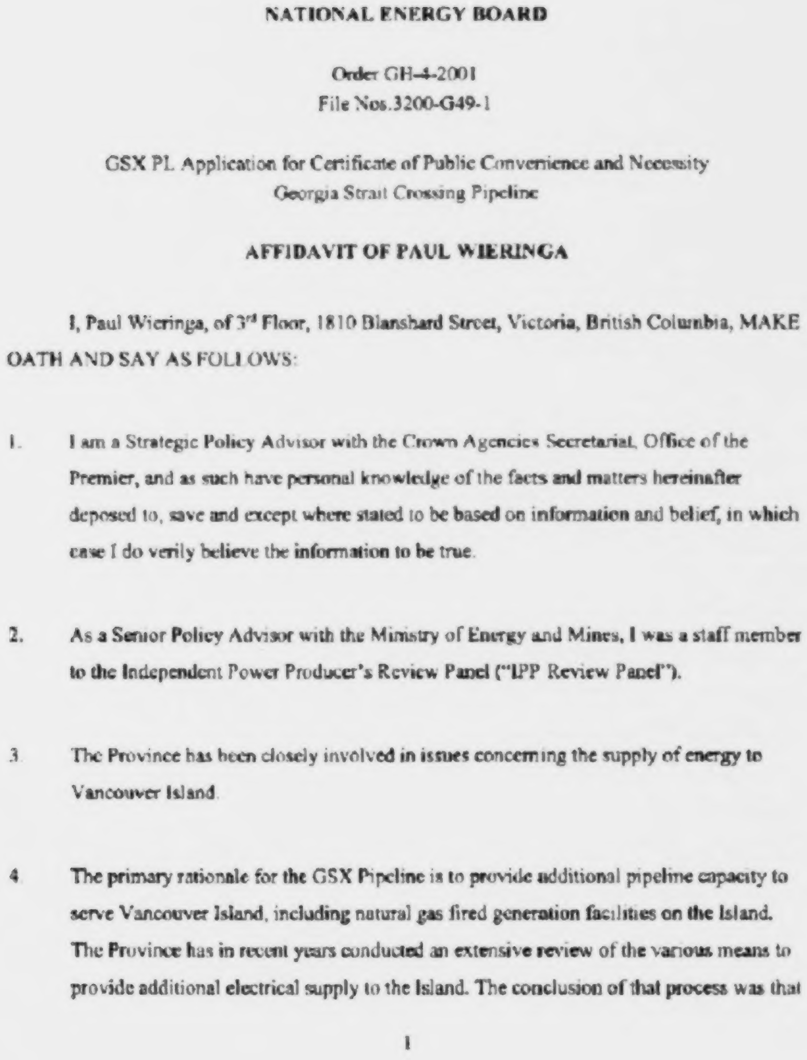
ROW	See **Right-Of-Way**.
Run-Of-River	A hydroelectric facility that operates using only available streamflow.
Secondary Energy	The additional energy that is available when stream flow exceeds critical conditions.
Selective Catalytic Reduction (SCR)	A method of reducing nitrogen oxide emissions by injecting ammonia into the exhaust gases from a thermal plant and passing these gases over a catalyst.
Self-Generation	Generation of electricity by a customer for part or all of its own load requirements.
Sequence	The order in which resources should be acquired to meet the demand growth.
SFN	Snuneymuxw First Nation.
Simple-Cycle Combustion Turbine (SCCT)	A stand-alone combustion turbine, similar to a jet engine, connected to an electrical generator and used for power generation.
Single Contingency Criterion	Requirement that when a single component in the transmission system (such as a line, transformer, or a generator) is lost, there should be no loss of firm load. See also **N-1**.
SNCR	Selective non-catalytic reduction.
SO_2	Sulphur dioxide.
Social Costing	An approach which incorporates environmental and societal values in decision-making.
Spill	Water released over a spillway without passing through turbines to produce electricity.
ST	Steam turbine.
STG	Steam Turbine Generator. See also **Turbine Generator**.
Storage	The water held in a reservoir for power generation or flood control.
Streamflow	The rate at which flowing water passes a given point, measured in cubic metres per second (m^3/s).
Substation	An electrical switching station to terminate transmission lines and/or a station at which transmission voltage is reduced to a level suitable for subtransmission or distribution systems.
Subtransmission	Transmission lines of 230 kV or less and higher than 35 kV. Subtransmission lines generally supply regional loads.
Sumas Hub	One of the major pipeline hubs of the North American natural gas market; located in Washington State, just south of the Canada-US border. Used as a reference point for quoting the market price of gas.

Supply-Side Resources	Options that supply additional electricity, including new generation projects, coordination and purchases and improvements to existing facilities.
System Cost	The present value (PV) of system cost is a measure of economic efficiency. It measures the total cost, in present value terms, of an initiative or project to the people of the province.
System Stability	The ability of all parts of an electrical system to remain synchronized following an electrical disturbance such as the interruption of a transmission line. See also **Transient Stability**.
Terminal Station	The station at the end of a high voltage transmission line or cable circuit.
Thermal	Refers to the production of electricity through a combustion process.
Thermal Efficiency	See **Electric Generation Efficiency**.
Thermal Generation	Generation of electricity by means of the conversion of heat energy into electric energy by the controlled combustion of fossil fuels or biomass.
Thermal Host	The user of heat or steam produced through cogeneration. An example is a pulp and paper mill, which uses the steam for its industrial process.
Thermal Rating	The maximum amount of power that can pass through a piece of electrical equipment without causing damage due to overheating. In the case of transmission lines, the heating due to excessive power transfer may cause a line to sag below its specified height above the ground.
Time-Shift	The use of reservoir storage and peaking capability of BC Hydro's hydroelectric system to store water when available and generate electricity when needed.
Total Transfer Capability (TTC)	Amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specified set of defined pre- and post-contingency system conditions.
Transformer	An electrical device for changing electricity from one voltage to another.

Transient Stability, Transient Events	A transient event can be a lightning strike, line fault, or equipment failure resulting in a short circuit. Transient instability occurs when, due to a short-circuit, some generators accelerate and others decelerate so that the usual stabilizing forces cannot restore the generators to synchronous operation. This causes large swings in power flows and voltages over the transmission system, causing its protective systems to operate and causing the system to break up into separate areas, many of which will have much more or much less generation than their respective loads. The result of transient instability can be widespread blackouts. Transient phenomena can occur very quickly (typically in less than a second) due to a transient event.
Transmission	The transportation or conveyance of electricity in bulk at voltages over 60 kV.
Transmission System	Electrical facilities used to transmit electricity over long distances at voltages greater than 230 kV.
True Power	Active power or real power, i.e., power that does physical work. See **apparent power** and **reactive power**.
Turbine	A rotary device caused to turn by the movement of gases, steam or water.
Turbine Generator	A device that employs a turbine to spin a generator, harnessing the potential energy in high-pressure steam, hot high-pressure gases, water, or wind. The VIGP uses both a combustion turbine generator (**CTG**) and a steam turbine generator (**STG**). Combination of a turbine, which is driven by the combustion of natural gas and which in turn drives the generator.
Undeveloped Rivers	Rivers whose flows are currently unaffected by any storage or generation facilities.
Upgrade	An improvement to an existing facility.
VIEC	Vancouver Island Energy Corporation, wholly-owned subsidiary of BC Hydro and proponent of the **VIGP**.
VIGP	Vancouver Island Generation Project.
VIT	Vancouver Island Terminal—a substation near Duncan on Vancouver Island, to which the underwater HVDC and 138 kV AC transmission systems from the Mainland connect.
Volt (V)	Electromotive force (emf) is required to change the random motion of electrons into an electric current. The volt is the basic unit of electromotive force.

Voltage Collapse	A catastrophic voltage drop in a region where the transmission and distribution system is incapable of supplying the load. A system enters a state of voltage collapse or instability when an increase in load, system disturbance or change causes voltage to drop quickly or drift downward, and automatic and manual system controls are unable to halt the decay. Voltage collapse may take anywhere from a few seconds to minutes.
Voltage Stability	The ability of the electrical transmission system to withstand the failure of a system element such as a line or transformer without **voltage collapse** at the receiving (customer) end of the system.
Water Licences	The authority granted to BC Hydro by the Comptroller of Water Rights of the Province of British Columbia to store and divert water for generating electricity and other purposes.
Watt (W)	Basic unit given for the rate at which electric energy is generated or consumed. 1 watt = 1 J/s.
WECC	Western Electric Coordinating Council (formerly Western Systems Coordinating Council)—the body that sets electric system operating performance and reliability standards for members in Western Canada and the Western United States.
Wood Waste	The wood remaining after processing logs, and having no marketable use as a lumber or pulp product. About half of BC's wood waste is already utilized by cogeneration or stand-alone power plants, but large quantities are incinerated without energy recovery. The biggest surpluses are in the Central and Southern Interior regions.

Appendix B: Wieringa Affidavit (GSX PL Application)



NATIONAL ENERGY BOARD

Order GH-4-2001
File Nos.3200-G49-1

GSX PL Application for Certificate of Public Convenience and Necessity
Georgia Strait Crossing Pipeline

AFFIDAVIT OF PAUL WIERINGA

I, Paul Wieringa, of 3rd Floor, 1810 Blanshard Street, Victoria, British Columbia, MAKE OATH AND SAY AS FOLLOWS:

1. I am a Strategic Policy Advisor with the Crown Agencies Secretariat, Office of the Premier, and as such have personal knowledge of the facts and matters hereinafter deposed to, save and except where stated to be based on information and belief, in which case I do verily believe the information to be true.

2. As a Senior Policy Advisor with the Ministry of Energy and Mines, I was a staff member to the Independent Power Producer's Review Panel ("IPP Review Panel").

3. The Province has been closely involved in issues concerning the supply of energy to Vancouver Island.

4. The primary rationale for the GSX Pipeline is to provide additional pipeline capacity to serve Vancouver Island, including natural gas fired generation facilities on the Island. The Province has in recent years conducted an extensive review of the various means to provide additional electrical supply to the Island. The conclusion of that process was that

1

the preferred means of providing for the Island's electricity needs was through gas fired generation.

5. In 1994, the Provincial Government made a policy decision to consider other alternatives, and asked BC Hydro to issue a Request for Proposals ("RFP") for Independent Power Producer ("IPP") projects to supply electricity to meet the Province's increasing demands, including Vancouver Island. Forty-eight proposals were submitted in response to that RFP, of which 10 were short listed for further evaluation. Staff from the Province, consultants and BC Hydro were involved in the social, economic and financial review of the submitted proposals.

6. In 1995, BC Hydro noted that security of supply to Vancouver Island was becoming critical. The aging 138 kV submarine cable circuits were approaching the end of their useful lives. BC Hydro forecast that Vancouver Island's demand for electricity would exceed the supply capacity of the existing electricity generation and transmission facilities within a decade. BC Hydro's proposed solution was to re-power the natural gas fired Burrard Thermal power plant to generate additional electricity, and transmit that electricity to Vancouver Island through upgraded submarine transmission cable capacity (a seventh 500 kV cable).

7. Of the 10 short listed proposals, three used biomass fuel, three used natural gas and four involved hydroelectric facilities. Each of the 10 proponents were invited by BC Hydro to improve their submissions during later September and early October 1995. BC Hydro then conducted a further analysis of these revised proposals. The Crown Corporation Secretariat commissioned Acres International Limited for an external review of the issue of transmission credits for locating new generation on Vancouver Island. One of the proposals was withdrawn by the proponent, two were removed from further consideration, two wood residue projects were approved, leaving five projects.

8. On April 15, 1996 the Provincial Government appointed the Independent Power Producers Review Panel (IPP Review Panel), lead by John Allan, and consisting of Dr. Jon O'Riordan, Dr. Bruce McRae, Prof. Bradley and a transmission specialist, Walter Nieboer, assisted by staff from Crown Corporations Secretariat and the Ministry of Energy and Mines, including myself. The IPP Review Panel's mandate was to evaluate the remaining five short listed proposals: three small hydro projects and two natural gas fired cogeneration plants (the Island Cogeneration Plant ("ICP") at Campbell River and the Port Alberni Cogeneration Plant ("PACP") at Port Alberni). The IPP Review Panel analyzed the financial, environmental and social costs of these proposals and compared them with BC Hydro's preferred strategy of repowering a unit at the Burrard Thermal generating plant and constructing a new transmission line to serve Vancouver Island. It concluded that the ICP and PACP proposals ranked first and second, respectively. Based upon the IPP Review Panel's conclusions, in the fall of 1996 the Province directed BC Hydro to enter into negotiations for an electricity purchase agreement ("EPA") with the ICP proponents. On October 7, 1998 the Province and BC Hydro announced the successful conclusion of an EPA. The plant has been constructed and is currently undergoing testing.

9. In addition, in September 1997 the Provincial Government directed BC Hydro to negotiate a key principles agreement with the proponents of the Port Alberni Cogeneration Project. This project was granted a Project Approval Certificate by the Ministers of Employment and Investment and Environment, Lands and Parks on December 10, 1999, but did not ultimately proceed. BC Hydro and Calpine are currently considering a site on Vancouver Island for the construction of a new generating facility.

10. Finally, as a result of the development of these proposals, BC Hydro solicited bids for natural gas transportation capacity to Vancouver Island, to fuel the natural gas fired

electricity generation plant(s). A team of representatives of BC Hydro, the Provincial Government and private consultants analyzed the three bids received, and determined that the bid from Williams was the most favourable. Based on this evaluation the Provincial Government approved BC Hydro's request to enter into negotiations with Williams, and to form a partnership, namely GSX PL. Those negotiations and partnership have culminated in the application now before the NEB to construct the GSX pipeline by GSX PL.

SWORN BEFORE ME at the City of Victoria, in the Province of British Columbia, this 14th day of February, 2002.	)	
A Commissioner for taking Affidavits within British Columbia	)	PAUL WIERINGA

Appendix C: Vancouver Island Capacity/Peak Demand Data

	2003/04	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Peak Demand									
December 2002 Load Forecast (includes transmission losses)	2189	2230	2263	2293	2320	2346	2377	2406	2438
Estimated Power Smart Peak Reductions	25	54	69	81	92	102	102	102	102
Peak Demand with Power Smart	**2164**	**2176**	**2194**	**2212**	**2228**	**2244**	**2275**	**2304**	**2336**
Firm Supply Capacity									
500 kV AC Transmission System	1300	1300	1300	1300	1300	1300	1300	1300	1300
HVDC Transmission System	240	240	240	240	0	0	0	0	0
Island Cogeneration Project	164	220	240	240	240	240	240	240	240
Existing On-Island Hydro	450	450	450	450	450	450	450	450	450
Allowance for Green Energy & Customer Based Generation	0	0	0	25	25	25	25	25	25
Total Supply Capacity	**2154**	**2210**	**2230**	**2255**	**2015**	**2015**	**2015**	**2015**	**2015**
Supply/Demand Balance After Power Smart	(10)	34	36	43	(213)	(229)	(260)	(289)	(321)
Supply/Demand Balance Before Power Smart	(35)	(20)	(33)	(38)	(305)	(331)	(362)	(391)	(423)

Appendix D: EAO Scoping Order

IN THE MATTER OF THE ENVIRONMENTAL ASSESSMENT ACT S.B.C. 2002, c.43 (the ACT)

AN ENVIRONMENTAL ASSESSMENT OF THE VANCOUVER ISLAND GENERATION PROJECT (the PROJECT)

ORDER UNDER SECTION 11

WHEREAS:

A. On June 21, 2002, the Executive Director accepted for review an application from the Vancouver Island Energy Corporation (the Proponent) for a project approval certificate under the *Environmental Assessment Act,* R.S.B.C. 1996, c.119 (former Act) to construct and operate a 265 megawatt natural gas fired combined cycle electricity plant at Duke Point near Nanaimo, British Columbia;

B. The proposed location of the plant is in close proximity to Indian Reserves of the Snuneymuxw First Nation;

C. The BC Court of Appeal held in *R. v. Little* (1995), 131 D.L.R. (4th) 220, that the Snuneymuxw First Nation traditionally used the Nanaimo River for fishing and that the Douglas Treaty, by providing the Snuneymuxw First Nation with the right to carry on their "fisheries as formerly", protects that right against potential infringements;

D. Section 51(3) of the Act requires that the assessment of the Project under the former Act be continued and disposed of as an application for an environmental assessment certificate;

E. Transition Order #02-17 issued on December 30, 2002 requires that the application and supporting information provided to date by the Proponent be accepted as an application under section 16 of the Act;

F. On December 30, 2002, the Executive Director, in accordance with section 4 of the Act, delegated certain statutory and regulatory powers and duties in relation to the Project to the undersigned Project Assessment Director;

G. The public had opportunity to comment on the application from July 24, 2002 to October 22, 2002; and

H. Certain members of the former Project Committee, established under the former Act, have requested that their views on issues considered during the assessment be included in the assessment report, which is part of the referral to Ministers for a decision on the Proponent's application for an environmental assessment certificate.

NOW THEREFORE:

Pursuant to section 11 of the Act, I order that the environmental assessment of the Project be conducted according to the scope, procedures and methods set out in Schedule A.

Anne Currie

Anne Currie

Project Assessment Director

Vancouver Island Generation Project

Dated February 5, 2003 at Victoria, British Columbia

SCHEDULE A

SCOPE, PROCEDURES AND METHODS FOR THE ENVIRONMENTAL ASSESSMENT OF THE VANCOUVER ISLAND GENERATION PROJECT (the PROJECT)

The proposal to construct and operate the Vancouver Island Generation Project (the Project) constitutes a reviewable project pursuant to Part 4 of the *Reviewable Project Regulations* (B.C. Reg. 370/02) because the power plant is a new facility with a rated nameplate capacity of ≥50 MW of electricity.

1. APPLICATION DOCUMENT

(i) The application for an environmental assessment certificate from the Proponent consists of the following documents and may be supplemented by the Proponent, where required by the Project Assessment Director, to address issues identified during the course of this assessment:

a) Vancouver Island Generation Project: Application to the British Columbia Environmental Assessment Office, Volume I – June 2002; and

b) Vancouver Island Generation Project: Application to the British Columbia Environmental Assessment Office, Volume II – June 2002.

2. SCOPE OF THE PROJECT

(i) The Project will include the following on-site and off-site components and activities:

- a natural gas fired combined cycle power plant;
- a natural gas feeder pipeline;
- a water supply pipeline;
- a pipe to transport wastewater to the main sewage treatment plant;
- an upgrade of the existing power transmission line; and
- an upgrade of Hooker Road.

3. SCOPE OF THE ASSESSMENT

i) The assessment of the Project will include consideration of the potential for effects to air quality, health, water, wildlife and fisheries, vegetation, social, economic and heritage values, and First Nations interests, including the potential for infringement of asserted Aboriginal and Douglas treaty rights.

4. PROCEDURES AND METHODS

i) Access to Information

a) The Project Information Centre will make available the records generated for the purposes of the assessment in accordance with section 6 of the Public Consultation Policy Regulation (B.C. Reg. 373/02).

ii) Review of the Application

a) Where requested by the Project Assessment Director, the Proponent must respond to issues that are within the scope of the assessment and are identified in government, First Nations or public comments received during the assessment.

iii) Preparation of the Assessment Report

a) Prior to a referral to Ministers, the Project Assessment Director will provide those representing provincial and federal government agencies, the Snuneymuxw First Nation and local governments in the area potentially affected by the Project with an opportunity to review and comment on the draft assessment report, and the views of those representatives, on issues relevant to the assessment of the Project, will be included in the report.

b) Prior to a referral to Ministers, the Project Assessment Director will offer to meet with the Snuneymuxw Chief and Council to discuss the Snuneymuxw's comments on the application and draft assessment report.

iv) Referral to Ministers

a) The Project Assessment Director will refer the Proponent's application for an environmental assessment certificate to Ministers for a decision by April 17, 2003.

Appendix E: Rated Outputs and Efficiencies of GE CCGTs

The following table compares rated power outputs and efficiencies of GE CCGT plant designs.[93]

GE Combined Cycle Designation	Note*	Net Plant Power (MW)	Net Plant Heat Rate (kJ/kWh)	Thermal Efficiency (% LHV)
S106B	1	64.3	7340	49.0
S206B	1	130.7	7230	49.8
S406B	1	261.3	7230	49.8
S107EA	1	130.2	7175	50.2
S207EA	1	263.6	7070	50.9
S106FA	2	107.1	6795	53.0
S206FA	2	217.0	6705	53.7
S107FA	2	262.6.	6425	56.0
S207FA	2	529.9	6375	56.5
S107FB	2	280.3	6280	57.3
S207FB	2	562.5	6260	57.5
S107H	3	400.0	6000	60.0

*Notes:

Design basis: (a) site conditions: 15 C°, 101.3 kPa, 60% relative humidity; (b) steam turbine exhaust pressure 1.2 inches Hg; and performance is net plant with allowance for equipment and plant auxiliaries, including those associated with a once-through cooling water system.

1. Three-pressure, non-reheat, heat-recovery feedwater heating steam cycle.
2. Three-pressure, reheat, heat-recovery feedwater heating steam cycle with integrated fuel, gas-heating system.
3. Three-pressure, reheat, heat-recovery feedwater heating steam cycle with integrated turbine steam- and air-cooling and fuel-heating systems.

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[93] From "GE Combined-Cycle Product Line and Performance", GER-3574G, prepared by D.L. Chase and P.T. Kehoe, GE Power Systems, Schenectady, NY (October 2000).

Appendix F: Efficiency of Cogeneration and Stand-Alone CCGTs

To estimate the VIGP's thermal efficiency in a cogeneration configuration, it was assumed to be designed for generating steam and electricity with an average ratio of thermal to electrical energy of 0.3, the same as the ICP. In this case, the average annual efficiency of total thermal and electrical energy generation would be virtually the same as the ICP's, because the ICP uses similar technology to the proposed VIGP and provides steam to a large pulp and paper mill. The average annual efficiency in this case is 66.5%.

To estimate the VIGP's thermal efficiency in a stand-alone configuration, it was assumed that electricity is generated by the VIGP and that thermal energy is generated at an industrial plant using a gas-fired boiler. The ratio of thermal to electrical energy was assumed to be 0.3, as in the cogeneration case. The gas-fired steam boiler was assumed to have a thermal efficiency (η_c) of 80%, typical of such equipment. Stand-alone electricity generation efficiency (η_e) was assumed to be 55%, as with the VIGP. The combined thermal efficiency of separate generation of electricity and thermal energy in this non-cogeneration case is:

$$
\begin{aligned}
\text{Thermal efficiency (\%)} &= \frac{(\text{Net Electrical Output} + \text{Thermal Energy to Host}) \times 100}{\text{Net Electrical output}/\eta_e + \text{Thermal Energy to Host}/\eta_c} \\
&= \frac{(1 + (\text{Thermal Energy to Host /Net Electrical Output})) \times 100}{1/\eta_e + (\text{Thermal Energy to Host/Net Electrical Output})/\eta_c} \\
&= \frac{(1 + 0.3) \times 100}{1/0.55 + 0.3/0.8} \\
&= 59\%
\end{aligned}
$$

The combined thermal efficiency of the VIGP in a non-cogeneration configuration with thermal energy supplied separately by a steam boiler is thus estimated to be 59%, approximately 7.5 percentage points lower than the estimated 66.5% thermal efficiency of the VIGP in a cogeneration configuration.

The net thermal and electrical generation efficiency of cogeneration CCGT plants is highly dependent on the host's thermal load profile and the delivery temperature, or grade, of the thermal energy. The highest efficiency is achieved with a host requiring a large volume of low-grade energy that could not otherwise be utilized in the CCGT to generate additional electricity, and recovering essentially all the available energy from the delivered thermal energy. The European Education Tool on Cogeneration[94] estimates the total efficiency of cogeneration combined cycle systems to be in the range of 70-88%; the ratio of produced thermal energy to electricity is in the range of 0.6-2.0. CIEEDAC[95] quotes a slightly lower efficiency range for cogeneration CCGT systems, i.e., 69-83%. The upper end of these ranges for cogeneration CCGT systems is significantly higher than shown by local experience at the ICP. Reaching such high levels would require close integration of a CCGT power plant's operation with the thermal energy needs of a thermal host.

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[94] "The European Educational Tool on Cogeneration", 2d edition, prepared for the EDUCOGEN project for the European Union (2001), available at *www.cogen.org/projects*.

[95] See note 66.

Appendix G: Reliability of GE F Class Gas Turbines

To meet electricity generation requirements in the 1990s, there was a significant move to develop new gas turbine technology that took advantage of higher firing temperatures. The new gas turbines offered increased efficiency and reduced emissions and were widely applied in North America in simple cycle configurations for peaking requirements and in combined cycle configurations with steam turbines for general service. The advantages offered by the new technology, and competition between manufacturers, resulted in the new generation of gas turbines being placed into service before the designs became fully tried in test applications. Consequently, some problems with these new gas turbines were encountered by all manufacturers, which had to be resolved after the gas turbines had already been placed in commercial service.

Various companies have commercialized advanced high-efficiency, low-NO_x gas turbines that utilize what is commonly referred to in the industry as F technology. GE and other manufacturers experienced problems when bringing F technology gas turbines into service. The manufacturers have introduced design modifications and maintenance procedures to address these issues. For example, the dry low No_x combustion system, generally accepted as a cost-effective approach to emissions control, has been updated to the current model in the 7FA generation of machines. Because management of combustion becomes more difficult with liquid fuels, CCGT operators generally limit fuel choice to natural gas only. GE also employs a “Generation 4” enhanced rotor in current models and specifies starting procedures to overcome earlier operating problems related to rotor design. All the modifications are incorporated in the PG 7241FA model, the most mature 7FA gas turbine manufactured by GE. The 7FA turbine was specifically selected for VIGP in preference to GE's next generation of F technology (7FB), which offers an increase in efficiency but which has not had wide commercial application.

GE F technology gas turbines are the most commonly used (70%) in installations in North America. As of the end of 2002, there were 508 GE F technology gas turbines in commercial operation, with approximately 7.1 million fired hours of total operation. 213 of these units, or 42%, had each accumulated over 8,000 fired hours. Commercial experience with these gas turbines is thus growing rapidly, increasing from 2.6 million fired hours as of December 1999, to 5 million hours as of March 2002, to the current level of over 7.1 million hours.

Data on the reliability of utility power plants is collected in the US by the North American Electric Reliability Council (NERC). NERC's most recent Generating Availability Report[96] contains 1997-2001 operating performance statistics reported by 178 utilities in the United States and Canada for various classes of fossil fuelled generating units. The combined cycle units of all sizes included in the survey had an average reliability factor (see below) of 98.0% and an average availability factor (see below) of 90.3% for the 1997-2001 period (unweighted by plant capacity). These plants were 14-17 years old at the time of the survey. When weighted according to capacity, the average reliability increases to 98.3% and the average availability increases to 91.3%. Performance data is also reported in the survey for conventional gas-fired power plants of 200-299 MW capacity (similar in size to VIGP) and that range in age from 33 to 37 years. These units had an average unweighted reliability of 95.5% and an average unweighted availability of 84.3%, which is lower than reported for the newer combined cycle plants. While these statistics include older generation gas turbines, the trend for reliability and availability reporting for the frame 7 gas turbines has improved to approximately 97% reliability and 91% availability currently for the industry as a whole.

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[96] *Generating Availability Report 1997-2001*, North American Electric Reliability Council, accessible at *http://www.nerc.com/~filez/gar.html* (gar2001.exe).

NERC does not report operating data specifically for GE F technology gas turbines, though it does report historical data for gas turbine and other generic types of generating plants under a mandate from the US government. Strategic Power Systems Inc. (SPS) collects data on the reliability of all types of gas turbine generating plants worldwide and by manufacturer and is the only known independent source for this information. Reliability and availability statistics reported by SPS for F technology gas turbines in electricity generating applications are calculated in accordance with the conventions in the Institute of Electrical and Electronics Engineers (IEEE) Standard 762:

- Reliability (%) = [1- (forced outage hours/unit period hours)] x 100
- Availability (%) = (available hours/unit period hours) x 100

A summary of reliability data voluntarily reported to SPS was obtained from GE for the period from 1998 through to the end of the third quarter of 2002. The report compares the reliability of GE's F technology gas turbines to the reliability of F technology gas turbines of comparable size from all suppliers.[97] These results show the following trends:

The simple cycle reliability of the GE 7F/FA gas turbine fleet averaged 98.3% through the third quarter of 2002, based on 43 units in commercial service responding to the survey, and has ranged from approximately 98% to 99% since 1998. This reported reliability of the GE 7F/FA units has been above the industry average over the last three years, based on 97 units of all makes responding to the survey. The average availability of the 43 GE 7F/FA gas turbines responding to the survey in 2002 was 94.4%.

According to Eldrid et al,[98] the GE target for the average simple cycle reliability of 7F/FA gas turbines is 99.0%. The survey results summarized above for the 43 reporting F technology gas turbines in commercial operation show that the average reliability of these turbines has achieved or exceeded the target in 3 of the last 5 years.

Looking ahead, the reliability of the GE PG7241FA gas turbine proposed for the VIGP will benefit from the modifications to the design that have been incorporated since the first GE F technology gas turbine went into commercial service in a combined cycle plant in 1990. In addition, the planned use of the machine at VIGP, in more or less continuous operation with a limited number of starts, will benefit expected reliability since, as a whole, F class units will supply megawatt output very efficiently at baseload.

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[97] GE, *Gas Turbine Reliability, Availability and MTBF Trends (1998-3Q02)* (December 2002). These data are collected through a voluntary reporting system, and the sample sizes are not intended to be statistically significant. However, they are the best available data and are independent in that they come from third party sources. The GE report simply summarizes the SPS data.

[98] R. Eldrid, L. Kaufman and P. Marks, *The 7FB: The Next Evolution of the F Gas Turbine* (GER-4194: April 2001).

BRITISH COLUMBIA UTILITIES COMMISSION

ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

SIXTH FLOOR, 900 HOWE STREET, BOX 251
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 2646

VIA FACSIMILE
(604) 623-4111

March 20, 2003

Mr. Ray Aldeguer
Senior Vice-President
Corporate Resources & General Counsel
British Columbia Hydro and Power Authority
333 Dunsmuir Street
Vancouver, B.C. V6B 5R3

Dear Mr. Aldeguer:

Re: Vancouver Island Energy Corporation
Certificate of Public Convenience and Necessity Application
for the Vancouver Island Generation Project

Further to your March 12, 2003 application for a Certificate of Public Convenience and Necessity for the above noted Project, we enclose Commission Order No. G-21-03.

Yours truly,

Robert J. Pellatt

cms
Enclosure

Post-it® Fax Note 7673 Date 3/20 # of pages 6
To MR. ALDEGUER
Fax# BC HYDRO
From RT PELLATT
Phone#

BCH/VIGP-DkPt CPCN/Wkshp/PHC Notice

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-21-03

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Vancouver Island Energy Corporation
(a Wholly-Owned Subsidiary of British Columbia Hydro and Power Authority)
Application for a Certificate of Public Convenience and Necessity
for the Vancouver Island Generation Project

BEFORE: P. Ostergaard, Chair)
P.G. Bradley, Commissioner) March 20, 2003

O R D E R

WHEREAS:

A. On March 12, 2003, Vancouver Island Energy Corporation ("VIEC") applied pursuant to Sections 45 and 46 of the Utilities Commission Act ("the Act") for a Certificate of Public Convenience and Necessity ("the Application") for the Vancouver Island Generation Project ("VIGP", "the Duke Point Project"); and

B. The VIEC is a wholly-owned subsidiary of British Columbia Hydro and Power Authority ("B.C. Hydro"). The Application states that the VIGP is B.C. Hydro's preferred option for securing reliable electricity supply for Vancouver Island and the Gulf Islands; and

C. The VIGP includes a combined-cycle natural gas turbine power generating plant at Duke Point near Nanaimo, a connection and upgrade to the existing transmission grid, a short gas supply pipeline and related works. The VIGP would provide 265 megawatts of power and has an estimated cost of $340 million and an expected in-service date of July 2006; and

D. The environmental, economic, social, heritage and health effects of the VIGP have undergone an assessment by the Environmental Assessment Office; and

E. The VIGP is integrally linked to the Georgia Strait Crossing Project ("GSX Project"), a proposed international natural gas pipeline from Washington State to Vancouver Island. The Canadian portion of the GSX Project is currently under review by the National Energy Board; and

F. The Commission requires that a regulatory process to deal with the Application be established.

NOW THEREFORE the Commission orders as follows:

1. Commission staff will submit initial written information requests to VIEC by Friday, March 21, 2003. VIEC will provide written responses by Monday, April 14, 2003.

2. The Commission will hold Workshops on the Application in Nanaimo on Tuesday and Wednesday, April 22 and 23, 2003 commencing at 9:00 a.m. The Workshops will address the following matters:

Tuesday April 22	- Vancouver Island Peak and Annual Demand and Supply - Condition of HVDC Cables and Reliability of Supply
Wednesday, April 23	- Feasibility of New Transmission Lines and Other Supply Alternatives - Vancouver Island Generation Project and GSX Project

3. The Commission will hold a Pre-hearing Conference in Nanaimo after the conclusion of the Wednesday, April 23 Workshop, to address procedural matters which will include, but not be limited to, the following:

   - scheduling,
   - completeness of the Application,
   - identification of principal issues,
   - process (information requests, written or oral public hearing),
   - location(s) of the proceeding, and
   - other matters that will enable the proceeding to efficiently review all aspects of the Application.

   A Regulatory Agenda and Timetable is attached as Appendix A to this Order. After the Pre-hearing Conference, the Commission will issue a further procedural order and regulatory agenda for the review of the Application.

2. VIEC will publish, as soon as possible, in display-ad format, the Notice of Workshop and Pre-hearing Conference, attached as Appendix B to this Order, in the Vancouver Sun and Province, the Victoria Times Colonist and such other news publications as may properly provide adequate notice to the public on Vancouver Island and the Gulf Islands.

3. The Application and supporting material will be made available for inspection at the Head Office of B.C. Hydro at 333 Dunsmuir Street. Vancouver, B.C., the Nanaimo Office of B.C. Hydro at 400 Madsen Road, and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C.

4. Intervenors and Interested Parties should inform the Commission, in writing, by Friday, April 11, 2003, of their intention to intervene and/or to attend the Workshop and Pre-hearing Conference.

DATED at the City of Vancouver, in the Province of British Columbia, this 20th day of March 2003.

BY ORDER

Peter Ostergaard

Peter Ostergaard
Chair

Attachments

Orders/BCH/VIEC DukePt VIGP Wkshps/PHC

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

APPENDIX A
to Order No. G-21-03
Page 1 of 1

REGULATORY AGENDA AND TIMETABLE

Vancouver Island Energy Corporation ("VIEC")
(a Wholly-Owned Subsidiary of British Columbia Hydro and Power Authority)
Application for a Certificate of Public Convenience and Necessity
for the Vancouver Island Generation Project

ACTION	DATES (2003)
Commission Staff file Initial Information Requests	Friday, March 21
Registration of Intervenors and Interested Parties	Friday, April 11
VIEC files Responses to Initial Information Requests	Monday, April 14
Workshop on Vancouver Island Peak and Annual Demand and Supply and on Condition of HVDC Cables and Reliability of Supply	Tuesday, April 22
Workshop on Feasibility of New Transmission and Other Supply Alternatives and on Vancouver Island Generation Project and GSX Project	Wednesday, April 23
Pre-hearing Conference	Wednesday, April 23

TIME AND LOCATION OF WORKSHOPS:

Time: 9:00 a.m.

Coast Bastion Inn
Ballroom
11 Bastion Street
Nanaimo, B.C. V9R 6E4
Telephone: (250) 753-6601

THE PRE-HEARING CONFERENCE WILL FOLLOW THE WORKSHOP ON WEDNESDAY, APRIL 23, 2003.

APPENDIX B
to Order No. G-21-03
Page 1 of 2

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Vancouver Island Energy Corporation Application for a Certificate of Public Convenience and Necessity for the Vancouver Island Generation Project

NOTICE OF WORKSHOPS AND PRE-HEARING CONFERENCE

Date:	Tuesday and Wednesday, April 22 and 23, 2003
Time:	9:00 a.m.
Location:	Coast Bastion Inn Ballroom 11 Bastion Street Nanaimo, B.C. V9R 6E4

THE APPLICATION

Vancouver Island Energy Corporation ("VIEC") has applied to the British Columbia Utilities Commission ("the Commission") pursuant to Sections 45 and 46 of the Utilities Commission Act ("the Act") for a Certificate of Public Convenience and Necessity for the Vancouver Island Generation Project ("VIGP", "the Duke Point Project"). VIEC is a wholly-owned subsidiary of British Columbia Hydro and Power Authority ("B.C. Hydro"). The Application states that the VIGP is B.C. Hydro's preferred option for securing reliable electricity supply for Vancouver Island and the Gulf Islands.

The VIGP consists of a combined-cycle natural gas turbine power generating plant at Duke Point near Nanaimo, a connection and upgrade to the existing transmission grid, a short gas supply pipeline and related works. It would provide 265 megawatts of power, has an estimated cost of $340 million and an expected in-service date of July 2006. Environmental and other impacts of the VIGP have undergone an assessment by the Environmental Assessment Office.

The VIGP is integrally linked to the Georgia Strait Crossing Project ("GSX Project"), a proposed natural gas pipeline from Washington State to Vancouver Island. The Canadian portion of the GSX Project currently is under review by the National Energy Board.

THE REGULATORY PROCESS

The Commission will hold Workshops on the Application in Nanaimo on Tuesday and Wednesday, April 22 and 23, 2003 commencing at 9:00 a.m. The Workshops will address the following matters:

Tuesday, April 22	- Vancouver Island peak and annual demand and supply - Condition of HVDC cables and reliability of supply
Wednesday, April 23	- Feasibility of new transmission lines and other supply alternatives - Vancouver Island Generation Project and GSX Project

The Commission will hold a Pre-hearing Conference in Nanaimo after the conclusion of the Workshop on Wednesday, April 23, to address procedural matters which will include, but not be limited to, the following:

- scheduling,
- completeness of the Application,

APPENDIX B
to Order No. G-21-03
Page 2 of 2

- identification of principal issues,
- process (information requests, written or oral public hearing),
- location(s) of the proceeding, and
- other matters that will enable the proceeding to efficiently review all aspects of the Application.

After the Pre-hearing Conference, the Commission will issue a further procedural order and regulatory agenda for the review of the Application.

PUBLIC INSPECTION OF THE DOCUMENTS

The Application and supporting material will be made available for inspection at the following locations:

British Columbia Hydro and Power Authority
Head Office: 17th Floor - 333 Dunsmuir Street, Vancouver, B.C.
(604) 623-4046

Regional Office: 400 Madsen Road, Nanaimo, B.C.
(250) 755-4700

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Vancouver, B.C.

The Application is available for viewing on B.C. Hydro's web site at *www.bchydro.com/vigp*.

INTERVENTIONS

Persons who expect to actively participate in the proceeding should register as Intervenors with the Commission, in writing, by Friday, April 11, 2003 identifying their interest in the Application, indicating if they plan to attend the Workshops and Pre-hearing Conference and providing an e-mail address if available. Intervenors will receive copies of the Application, all correspondence and filed documentation.

Persons not expecting to actively participate, but who have an interest in the Application, should register as Interested Parties with the Commission, in writing, by Friday, April 11, 2003 identifying their interest in the matter and indicating if they plan to attend the Workshops and Pre-hearing Conference. Interested Parties will receive a copy of the Application's Executive Summary and all Orders issued.

FURTHER INFORMATION

For further information, please contact Mr. Robert J. Pellatt, Commission Secretary, or Mr. Brian Williston, Manager, Engineering and Commodity Markets as follows:

Telephone:	(604) 660-4700	Facsimile:	(604) 660-1102
B.C. Toll Free:	1-800-663-1385	E-Mail:	Commission.Secretary@bcuc.com